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VOLUME III

SELECTED IMPACTS OF ELECTRIC UTILITY OPERATIONS IN THE OHIO RIVER BASIN (1976-2000): AN APPLICATION OF THE UTILITY SIMULATION MODEL

by

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16. ABSTRACT

This report was prepared as part of the Ohio River Basin Energy Study (ORBES), a multi-disciplinary research program supported by the Environmental Protection Agency. It presents selected results of a comprehensive evaluation of environmental, energy, economic and emissions impacts of electric utility operations in and around the Ohio River Valley through 2000. Impact projections are based on alternative scenarios defined by sets of assumptions regarding electricity demand and government and utility policies, such as alternative state implementation plan (SIP) emission limits, SIP compliance or no SIP compliance, alternative generating unit lifetimes, different rates of electricity demand growth, and different utility dispatching criteria.

Among the most important results are those concerning: (1) The dominant contribution to regional SO_2 emissions by SIP-governed, coal-fired generating units; (2) The base case scenarios and the effects of utility compliance with SIPs for SO_2, NO_x and particulate emissions; (3) The sensitivity of costs, SO_2 emissions, and electricity prices to generating unit lifetimes, stricter SIP limits, electricity demand, and a least-emissions dispatching criterion.

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FOREWORD

The Ohio River Basin Energy Study (ORBES) is an interdisciplinary, multi-university inquiry into the environmental, economic, and social impacts of energy facility development in a major portion of the Ohio River Basin. The study was initiated by the U.S. Environmental Protection Agency in 1976 in response to a directive from the U.S. Senate Appropriations Committee.

Most of the ORBES research was conducted by a group of faculty members at the University of Illinois, Indiana University, the University of Kentucky, the University of Louisville, The Ohio State University, the University of Pittsburgh, Purdue University, and West Virginia University. In a few instances, the necessary expertise was found at other universities or independent research organizations.

This report is one of a series produced in support of the overall ORBES assessment. For a summary of the entire study, see Ohio River Basin Energy Study (ORBES): Main Report, by the ORBES Core Team, also being published by the U.S. Environmental Protection Agency.

ABSTRACT

This report presents selected results of a comprehensive evaluation of the environmental, energy, economic, and emission impacts of electric utility operations in and around the Ohio River Valley from 1976 through the year 2000. These results — impact projections based on alternative scenarios defined by sets of assumptions regarding electricity demand and government and utility policies — were developed by Teknekron Research, Inc., using the Utility Simulation Model, in support of the congressionally mandated Ohio River Basin Energy Study (ORBES). The scenarios, specified by the ORBES Core Team, were designed to investigate the impacts of a number of factors — for example, alternative State Implementation Plan (SIP) emission limits, SIP compliance or no SIP compliance, alternative generating-unit lifetimes, different rates of growth in electricity demand, and different utility dispatching criteria.

The findings in this report illuminate implications of current and potential government and utility practices for future utility costs, air pollutant emissions, and electricity prices.

The report briefly reviews the recent emission levels attributable to coal-fired power plants in the ORBES counties and then turns to the key issues in the region. It translates the issues raised by these questions into scenarios that were examined using the Utility Simulation Model.* Finally, the results are presented. These results concern:

- The dominant contribution to regional sulfur dioxide (SO_2) emissions by SIP-governed, coal-fired generating units

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* For a description of the Utility Simulation Model, see Teknekron Research, Inc., Utility Simulation Model Documentation, vol. I, Overview, Model Outputs, and Analytic Structure, R-009-EPA-79, prepared for U.S. Environmental Protection Agency, office of Research and Development, Office of Energy, Minerals, and Industry (Washington, D.C., July 1979).

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- The base-case scenarios and the effects of utility compliance with State Implementation Plans (SIPs) for SO_2, NO_x, and particulate emissions
- The sensitivity of costs, SO_2 emissions, and electricity prices to generating-unit lifetimes
- The sensitivity of costs, SO_2 emissions, and electricity prices to stricter SIP limits
- The sensitivity of costs, emissions, and electricity prices to rates of growth in electricity demand
- The sensitivity of costs, SO_2 emissions, and electricity prices to a least-emissions system dispatching criteria

The findings of this integrated study suggest that electricity prices, air pollutant emissions, and hence air quality in the ORBES counties and in locations downwind will be significantly influenced by future utility and government decisions, particularly regarding the implementation of SO_2, NO_x, and particulate emission regulations and the expected lifetimes of SIP-regulated coal-fired generating units.

EXECUTIVE SUMMARY

The counties of concern in the congressionally mandated Ohio River Basin Energy Study (ORBES) contain an extensive number of coal-fired steam electric generating units located primarily along the Ohio River. The states encompassing the ORBES counties include all of Kentucky, most of West Virginia, and major portions of Illinois, Indiana, Ohio, and Pennsylvania.

In the mid-1970s, about 80 percent (9 million tons) of the SO_2 emissions from all sources in the ORBES counties came from coal-fired power plants. Thus, coal-fired power plants in the ORBES counties accounted for nearly 47 percent of total U.S. electric utility SO_2 emissions (and for 32 percent of total U.S. SO_2 emissions from all sources). Power plants in the ORBES counties also contributed about 47 percent of the area's NO_x emissions from all sources and about 33 percent of its particulate emissions.

A number of questions concerning the future growth and operation of electric utility power plants in the ORBES counties have been investigated using the Utility Simulation Model (USM) to provide detailed annual projections over the period from 1976 through 2000. Each USM projection includes detailed specifications of engineering performance and costs, fuel prices and characteristics, and numerous other factors influencing electric utility operations. Many factors, such as electricity demand growth rates and future power plant siting, were specified by the ORBES Core Team.

Future power-plant emission levels in the ORBES counties will be significantly influenced by numerous factors, including:

1. The stringency of State Implementation Plan (SIP) emission regulations and the degree of expected compliance with these regulations
2. Generating-unit lifetimes and anticipated retirement ages for existing SIP-regulated coal units

3. Criteria for dispatching coal units, i.e., least-cost dispatching (the usual method) or least-emissions dispatching (a possible option)

4. Growth rates of electricity demand

The answers to several key questions indicate the availability of a wide range of options for reducing future emission levels in the ORBES counties. SO_2 emissions in 2000 could conceivably be slightly higher than they are today or could be reduced to less than half the 1976 levels, depending upon additional consumer costs actually incurred.

- **How sensitive are ORBES county emissions to compliance with State Implementation Plan emission regulations for coal-fired power plants?**

If all coal-fired power plants comply fully with SIP emission limits by 1985, SO_2 emissions in the ORBES counties could decrease to about 6.1 million tons. This amounts to a 1985 reduction of 32 percent over 1976 levels and 40 percent over the 1985 levels projected to occur in the absence of compliance.

Despite current emission regulations, NO_x emissions are expected to increase from the 1976 level of about 1.5 million tons, primarily in proportion to electricity demand growth. By the year 2000, NO_x emissions could be 0.5 to 1.0 million tons greater than in 1976.

Dramatic reductions in particulate emissions can be expected if compliance with SIP particulate emission limits occurs. With compliance, particulate levels will fall by about 84 percent below the levels that could occur in the absence of compliance. Particulate emission levels in the ORBES counties will amount to about 0.2 million tons in the year 2000.

- **How will emissions in the ORBES counties be affected if there is no compliance with power-plant SIP emission limits?**

SO_2 emissions in the future will increase over 1976 levels if there is no compliance with SIP emission regulations. Between 1976 and 1985, SO_2 emissions will increase from 8.9 million tons to 10.1 million tons, a 13 percent rise. Between 1985 and 2000, SO_2 emissions will further increase if all SIP-regulated coal units remain on line.

In the absence of compliance with SIP emission limits, particulate emissions in 1985 could increase by 11 percent over 1976 levels and would be five times higher than the levels that would occur under compliance.

Future NO_x emissions will not be significantly affected by current SIP standards and will rise as electricity demand increases.

- **What are the costs of achieving emission reductions under the assumed SIP emission limits?**

Over the period from 1976 through 2000, complying with expected SIP SO_2 and particulate limits will increase cumulative revenues required from ultimate consumers and average electricity prices by about 10 percent over the case with no SIP compliance. (Over the ORBES counties, expected annual SIP limits for SO_2 average about 3.3 lb $SO_2/10^6$Btu. Appendix G discusses the importance of SIP emission averaging times.)

In 1985, consumers will pay 0.77¢ (or about 25 percent) more per kilowatt-hour to cover the cost of full SIP compliance in the ORBES counties. However, by 2000 the price differential due to SIP compliance will be only about 0.20¢/kWh (a 5 percent incremental increase over the case of no compliance).* Emissions after 1985 will be about 42 percent lower for SO_2 and 82 percent lower for particulates than they would be without compliance with SIP emission limits.

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* All costs in this report are given in 1975 dollars. To convert to 1980 dollars, multiply 1975 dollars by 1.42.

- **How sensitive are ORBES county emissions and electricity costs to stricter SIP emission regulations?**

Assuming that SIP limits will be more stringent than expected (with the stricter limits averaging 1.3 lb $SO_2/10^6$ Btu over the ORBES counties), and assuming that it will be feasible to achieve compliance with these stricter limits by retrofitting additional flue gas desulfurization (FGD) controls for SO_2, the stricter limits compared with the base-case SIP limits will result in a 20 percent greater decrease in SO_2 emissions in the ORBES counties from 1976 through 2000. Corresponding electricity prices in 1985 will increase by about [illegible] percent. (Average electricity prices as indicated by required revenues over the entire 1976-2000 period will increase by about 4 percent over the base case.)

- **How do projected high and low rates of growth in electricity demand affect future emissions and costs in the ORBES counties?**

SO_2 emissions in the ORBES counties are not highly sensitive to future rates of growth in electricity demand. The reason for this is that newer units will be significantly less polluting than SIP-governed units on the basis of emissions per Btu of fuel consumed. Even in the year 2000, SIP-governed coal-fired units will provide the dominant contribution to regional SO_2 emissions — about 67 percent — despite their share of the total generation dropping to only 25 percent.

By the year 2000, higher electricity demand growth (3.7 percent per year over the 1976-2000 period) will increase SO_2 emissions in the ORBES counties by only 8 percent over the moderate-growth base case (2.8 percent per year), while low growth (1.6 percent per year) will reduce emissions by 10 percent below the base case.

Under low growth, overall SO_2 emissions will be reduced primarily by the deferral of the newer, cleaner units. The newer coal plants built after 1985 will be required to remove approximately 85 to 90 percent of their potential SO_2 emissions; thus, it will take five or six new plants, each supplying the equivalent electricity generation of an average SIP plant, to produce the same amount of SO_2 emissions generated by this average complying SIP plant.

Differing electricity growth rates as well as rising fuel prices and capital costs will significantly affect the price of electricity over time. Under moderate demand growth and high demand growth, electricity prices will increase from 2.58¢/kWh in 1976 to 4.64¢/kWh and 5.70¢/kWh in the year 2000, respectively (measured in constant 1975 dollars). Compared with the base case of moderate growth in electricity demand, high growth will increase cumulative revenue requirements (i.e., average prices) over the 1976-2000 period by 22 percent, while low growth will reduce cumulative revenue requirements by 26 percent.

- **What effect do assumed generating-unit lifetimes have on ORBES county emissions and electricity costs?**

Between 1985 and 2000, SO_2 emission levels in the ORBES counties will be determined principally by the number of remaining SIP-governed plants. A coal-unit lifetime of 35 years (after which the unit is retired from service) will lead to SO_2 emission reductions once the retirements begin after 1985. However, generating-unit lifetimes of 45 years or more for coal-fired units will keep ORBES county SO_2 emissions level or even increase them between 1985 and 2000, depending on the amount of new capacity added. Very few retirements are planned before 1985.

A ten-year increase in expected generating-unit lifetimes (from 35 to 45 years) will cause SO_2 emissions to remain at or above 1985 emission levels, resulting in 29 percent greater annual SO_2 emissions in the year 2000.

Cumulative revenues required over the 1976-2000 period will decrease by about 4 percent if coal units are retired at 45 rather than 35 years of age. It should also be noted that both SO_2 emissions and utility costs after the year 2000 will be significantly affected by coal-unit retirement ages, since a large number of units will become candidates for retirement after 2000.

- **What environmental and economic impacts might result from dispatching coal-fired units on the basis of a "least emissions" criterion in contrast to the usual "least-cost" criterion?**

Dispatching coal-fired plants in a utility system under a criterion of least-emissions dispatching could reduce SO_2 emissions in the ORBES counties significantly as cleaner plants come on line after 1985. Under least-emissions dispatching, an increased share of the load would go to the newer coal plants (subject to the 1979 NSPS), and a decreased share to the SIP plants. Percentage SO_2 emission reductions would be greater than the proportional reduction in SIP-plant load, since the dirtiest units would be operated last in the new dispatch order. The increase in electricity prices would be about two percent. However, potential effects on individual system reliability should be examined.

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Principal Investigator

Stuart D. Liroff
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I. SUMMARY OF KEY FINDINGS

This and numerous other reports prepared in support of the congressionally mandated Ohio River Basin Energy Study (ORBES) present selected results of a comprehensive evaluation of the environmental, energy, economic, and air quality impacts of electric utility operations in and around the Ohio River Valley from 1976 through the year 2000. The electric utility impact projections described here are based on alternative sets of assumptions (scenarios) regarding electricity demand and government and utility policies. The assumptions were specified by the ORBES Core Team. The scenarios were designed to investigate a number of factors – for example, alternative State Implementation Plan (SIP) emission limits and the extent of compliance with these limits, alternative generating-unit lifetimes, different rates of growth in electricity demand, and different utility dispatching criteria.

The selected results discussed in this report concern the future utility costs, air pollutant emissions, and electricity prices projected by the Utility Simulation Model (USM). The findings illuminate the implications of current government and utility practices and of several future alternatives.

This Summary of Key Findings distills the detailed discussions of scenarios and results presented in Chapters II and III. Note that all costs and prices given throughout the report are in constant 1975 dollars. These costs and prices can be expressed in 1980 dollars by multiplying by 1.42. The Summary begins with a brief review of the recent emission levels attributable to coal-fired power plants in the ORBES region. Then the discussion turns to the questions of concern in the region and describes the translation of the issues raised by these questions into the scenarios that were examined using the USM. Finally, the key results are summarized. These results concern:

- The dominant contribution to sulfur dioxide (SO_2) emissions in the ORBES counties by SIP-governed, coal-fired generating units

- The effects of utility compliance with State Implementation Plans (SIPs) for SO_2, NO_x, and particulate emissions under the base-case scenario

- The sensitivity of capital costs, SO_2 emissions, and electricity prices to generating-unit lifetimes

- The sensitivity of capital costs, SO_2 emissions, and electricity prices to SIP limits

- The sensitivity of capital costs, SO_2 emissions, and electricity prices to rates of growth in electricity demand

- The sensitivity of capital costs, SO_2 emissions, and electricity prices to alternative system dispatching criteria

The findings of this integrated study suggest that electricity prices, air pollutant emissions, and hence air quality in the ORBES counties and in locations downwind will be significantly influenced by future utility and government decisions, particularly regarding the implementation of emission regulations and the operation and expected lifetimes of SIP-regulated coal-fired generating units.

The ORBES Counties

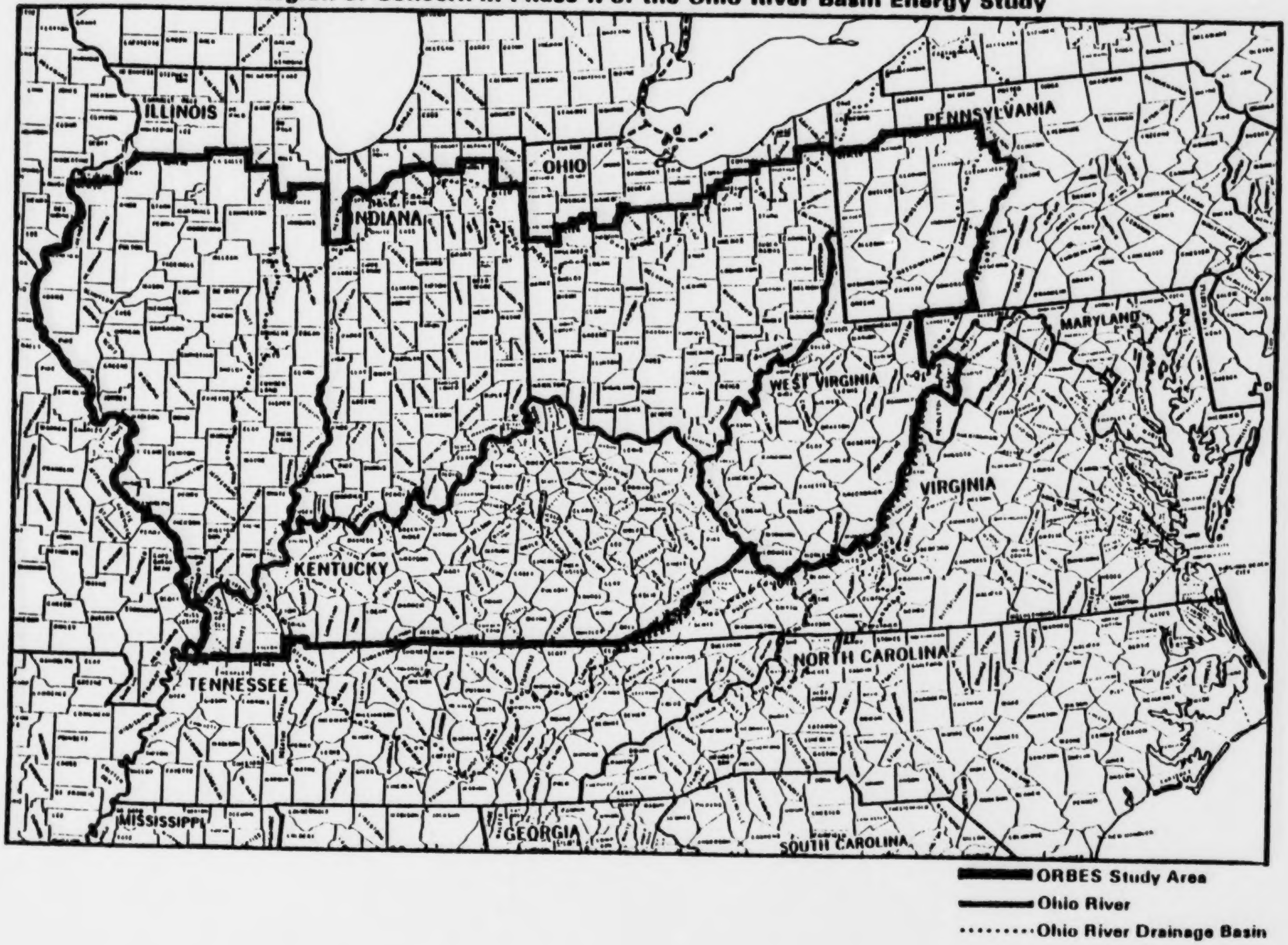
The counties of concern contain an extensive number of coal-fired steam electric generating units located primarily along the main stem of the Ohio River.

The ORBES study area (Figure 1-1) includes all of Kentucky, most of West Virginia, and major portions of Illinois, Indiana, Ohio, and Pennsylvania. In the mid-1970s, coal-fired power plants in the ORBES counties emitted about 9 million tons of SO_2, or 80 percent of the area's SO_2 emissions, thus accounting for nearly 47 percent of total U.S. electric utility SO_2 emissions (and for 32 percent of total U.S. SO_2 emissions from all sources).

Power plants in the ORBES counties also contributed about 47 percent of the area's NO_x emissions from all sources and about 33 percent of its particulate emissions.

Figure I-1

Region of Concern in Phase II of the Ohio River Basin Energy Study


ILLINOIS
INDIANA
OHIO
PENNSYLVANIA
MARYLAND
WEST VIRGINIA
VIRGINIA
KENTUCKY
TENNESSEE
NORTH CAROLINA
MISSISSIPPI
GEORGIA
SOUTH CAROLINA
ORBES Study Area
Ohio River
Ohio River Drainage Basin

The Translation of Issues into Scenarios

A first step in this study for ORBES was to translate issues into scenarios. These scenarios represented alternative assumptions about the future. They were designed by the ORBES Core Team to compare and contrast specific issues under future circumstances, but not to predict the "most likely" future. These issues were then examined using the Utility Simulation Model.

Of the many issues raised by the ORBES Core Team, this report addresses the following:

- How sensitive are ORBES county emissions to compliance with State Implementation Plan emission regulations for coal-fired power plants?
- What are the costs of achieving emission reductions under the assumed SIP emission limits?
- How will emissions in the ORBES counties be affected if there is no compliance with power-plant SIP emission limits?
- How sensitive are ORBES county emissions and electricity costs to stricter SIP emission regulations?
- How do projected high and low rates of growth in electricity demand affect future ORBES county emissions and electricity costs?
- What effect do assumed generating-unit lifetimes have on ORBES county emissions and electricity costs?
- What environmental and economic impacts might result from dispatching coal-fired units on the basis of a "least emissions" criterion in contrast to the usual "least cost" criterion?
- How will these various alternatives affect air quality in the ORBES counties?

As indicated by the Scenario Matrix (Figure I-2), these issues were synthesized into seven major scenarios to be analyzed with the USM.

Figure 1-2

Scenario Matrix

		VARIATIONS IN ELECTRICITY DEMAND			
		Low Demand 35-Year Generating Unit Lifetime	Base Case Moderate Demand 35-Year Generating Unit Lifetime	Higher Demand 35-Year Generating Unit Lifetime	Higher Demand 45-Year Generating Unit Lifetime
POLICY VARIABLES	Current SIPs, Compliance	Scenario 4	Scenario 2	Scenario 7b	Scenario 7
	No SIP Compliance	–	Scenario 2d	–	–
	Strict SIPs, Compliance	–	Scenario 1	–	–
	Least-Emissions Dispatching	–	–	–	Scenario 7a

Each scenario driving the USM projections includes detailed specifications of engineering performance and costs, fuel prices and characteristics, and numerous other factors influencing electric utility operations. Many of these factors, such as electricity demand growth rates and the siting of future power plants, were specified by the ORBES Core Team.

As we will show, future emission levels in the ORBES region will be significantly influenced by numerous factors, including government policies and future utility decisions. Among the potential factors are:

1. State Implementation Plan emission limits and the extent of compliance with these limits
2. Generating-unit lifetimes for existing SIP-regulated coal units
3. Criteria for dispatching coal units, i.e., least-cost dispatching (the usual method) or least-emissions dispatching (a possible option)
4. Growth rates of electricity demand

The effects of these factors can be determined by comparing the results of selected scenarios in which only one key parameter was varied:

Factors	Scenarios to be Compared
SIP limits and compliance	1, 2, and 2d
Growth in electricity demand	4, 2, and 7b
Generating-unit lifetimes	7b and 7
Dispatching criteria	7 and 7a

First we summarize the major features of our emission projections. Then we compare and discuss the results of the principal scenarios.

It should be noted that power plants for which construction began before August 1971 are regulated by SIP standards. Those for which construction began between August 1971 and September 1978 are subject to the 1971 federal New Source Performance Standards (NSPS), while those for which it began after September 1978 are subject to the 1979 revised New Source Performance Standards (RNSPS). In this report we frequently classify coal-fired steam generating units as subject to either SIP, NSPS, or RNSPS emission regulations.

Summary of SO_2 Emission Projections

A wide range of options is available to reduce future SO_2 emission levels in the ORBES counties. SO_2 emissions in 2000 could conceivably be slightly higher than they are today or could be reduced to less than half the 1976 levels.

SIP-regulated coal-fired units account for the great bulk of electric utility SO_2 emissions in the ORBES counties over the time horizon of this study. Indeed, in the year 2000 nearly 70 percent of projected utility SO_2 emissions in these counties could still come from SIP-regulated plants. Therefore, the various options for reducing regional SO_2 emissions turn on the extent to which these plants are operated, the manner in which they are operated, and the amount of emission control required. The following summary of SO_2 emission projections illuminates some options and also points up the effects of higher versus lower rates of growth in electricity demand.

Compliance versus Noncompliance with Expected SIPs. Between 1976 and 1985, SO_2 emissions in the ORBES counties will increase from 8.9 million tons to 10.1 million tons if compliance with the expected SIPs does not occur. If SIP compliance occurs by 1985, however, SO_2 emissions will decrease to about 6.1 million tons, a reduction of 32 percent over 1976 levels and a reduction of 40 percent over the 1985 levels projected in the absence of compliance. In the year 2000, under compliance with the expected SIPs and all other base-case assumptions of Scenario 2, SO_2 emissions amount to about 4.4 million tons.

By "expected SIPs" we mean the SIP limits of 1985 as anticipated in early 1979. Appendix G briefly describes how the SO_2 projections for 2000 are affected if the 1985 SIP limits that are anticipated now, in 1980, are assumed instead. Because of the variability of coal sulfur content, the averaging period over which SIP compliance is determined will significantly effect the level of annual emissions from an individual power plant. The averaging period can range from two hours to annual depending on the state and the generating unit's SIP limit. If each unit complies in its SIP limit and stated averaging period, then the base-case SO_2 projection of about 4.4 million tons in 2000 still holds, if all other assumptions also hold. However, if SIP compliance occurs but the SIP limits are interpreted as annual averages for all units in the ORBES counties, annual SO_2 in 2000 may be higher than those projected here by 0.5 to 1 million tons.

Stricter SIPs versus Expected SIPs. Over the ORBES region, expected SIPs for SO_2 average about 3.3 $lb/10^6$ Btu. If stricter SIPs were imposed, averaging 1.3 lb $SO_2/10^6$ Btu, SO_2 emissions in 2000 could be reduced by 41 percent over the base case with compliance.

Effects of Retiring SIP Plants or Reducing their Loads. SO_2 emission reductions between 1985 and 2000 will occur if:

- SIP-regulated plants are retired and replaced by newer, cleaner plants subject to the 1979 revised New Source Performance Standards (RNSPS)
- Newer, cleaner units are operated at increased loads, and SIP units at reduced loads, perhaps achievable if traditional least-cost dispatching is replaced by least-emissions dispatching

A 35-year life for coal units will lead to the retirement of 22.9 gigawatts (about one-third) of existing SIP capacity by the year 2000. Under the moderate rates of growth in electricity demand specified in the base case, SO_2 emissions will decrease by the year 2000 to 4.4 million tons. With a 45-year life for coal units, however, only 5.9 GW of SIP capacity will be retired by 2000. Under these circumstances, SO_2 emissions after 1985 will decline only slightly and could even increase between 1985 and 2000 if demand grows at 4.0 percent per year or more.

The dispatching of coal units according to a least-emissions rather than least-cost criterion to meet daily load requirements might significantly reduce SO_2 emissions in the ORBES counties to as little as 3.3 million tons in 2000. This would occur because load would be shifted from the SIP plants to newer plants subject to the 1979 RNSPS. (Whereas the SIP plants will emit an average of about 3.3 lbs $SO_2/10^6$ Btu after compliance, the newer, post-1985 plants will emit only about 0.6 lb $SO_2/10^6$ Btu.)

Higher versus Lower Demand Growth. SO_2 emission levels will also be determined by rates of growth in electricity demand. Under higher demand growth rates (3.6 percent per year between 1980 and 2000) and the 35-year retirement age, SO_2 emissions in the year 2000 are projected to total 4.7 million tons. Under more moderate growth rates (the base-case rates, averaging 2.5 percent per year), SO_2 emissions in 2000 are projected to decline to 4.3 million tons. Finally, under the low rates (1.6 percent per year), SC_2 emissions in 2000 are projected to drop to about 3.9 million tons.

The reason why low rates of growth in electricity demand reduce SO_2 emissions projected under the base-case moderate rates by only 10 percent is that most of the SIP plants are assumed to remain in service, while the newer, cleaner units are deferred.

Summary of NO_x Emission Projections

Nitrogen oxide (NO_x) emissions in the ORBES counties are expected to increase, primarily as a function of electricity demand.

NO_x emissions in the ORBES counties are projected to increase from the 1976 levels of 1.5 million tons. The extent of the increase will depend principally on rates of growth in electricity demand rather than on currently applicable emission standards, since SIP and NSPS emission limits do not significantly limit NO_x emissions. By the year 2000, NO_x emissions in the ORBES counties could range from 2.0 million to 2.6 million tons.

Summary of Particulate Emission Projections

Dramatic reductions in particulate emissions can be expected as SIP compliance occurs. With compliance, the dominant concern regarding particulates after 1985 may shift from total tonnage emitted to particle size.

With base-case SIP compliance, particulate emissions are projected to decrease dramatically. By 1985, SIP compliance should reduce total particulate emissions by 1.3 million tons, an 84 percent reduction from the levels that could occur with no compliance. Since newer units are assumed to meet the 1971 New Source Performance Standards (NSPS) or the 1979 RNSPS, only a small increase in total particulate emissions is expected between 1985 and 2000 after SIP compliance occurs. Under these circumstances, the size distribution of emitted particulates may take on greater importance than the total tonnage of all particulates emitted.

Without SIP compliance, primary particulate emissions in 1985 will increase to 11 percent above the 1976 levels of about 1.4 million tons. It should be noted that additional particulates in the ambient air result from secondary conversions, occurring after particulate control devices have significantly reduced the primary particulate emissions.

The Dominant Contribution to ORBES County SO_2 Emissions by SIP Units

(Scenario 2)

Scenario 2, which assumes compliance with expected SIP limits by 1985 and a 35-year coal unit life, is the base-case scenario defined by the Core Team. In 1976, SIP-governed units generated almost all the electricity and resultant SO_2 emissions in the ORBES area. By 2000, under Scenario 2, their share of the area's electricity generation is projected to decrease to about 25 percent. However, their share of the area's utility SO_2 emissions is projected to remain dominant, at 67 percent.

Figure 1-3 illustrates the projected contributions of various types of generating units to both electricity generation and SO_2 emissions in the ORBES counties. Nuclear plants maintain a relatively constant contribution to generation after 1992, since, in accordance with Core Team specifications, no new nuclear units were added beyond those currently announced. For coal-fired units, the figure shows the yearly generation from units regulated by SIPs, by the 1971 New Source Performance Standards (NSPS), and by the 1979 revised NSPS (RNSPS). RNSPS units will utilize FGD to remove about 85 to 90 percent of their potential SO_2 emissions. Generation from the NSPS units will remain nearly constant after 1985, since coal units added after about that year will be regulated by the RNSPS. Thus, the generation from RNSPS units will increase over time and will surpass that of SIP units after about 1993. However, SO_2 emissions from SIP units in 1993 will still be five to six times greater than SO_2 emissions from RNSPS units.

The Base-Case Scenario and Effects of SIP Compliance (Scenario 2 versus Scenario 2d)

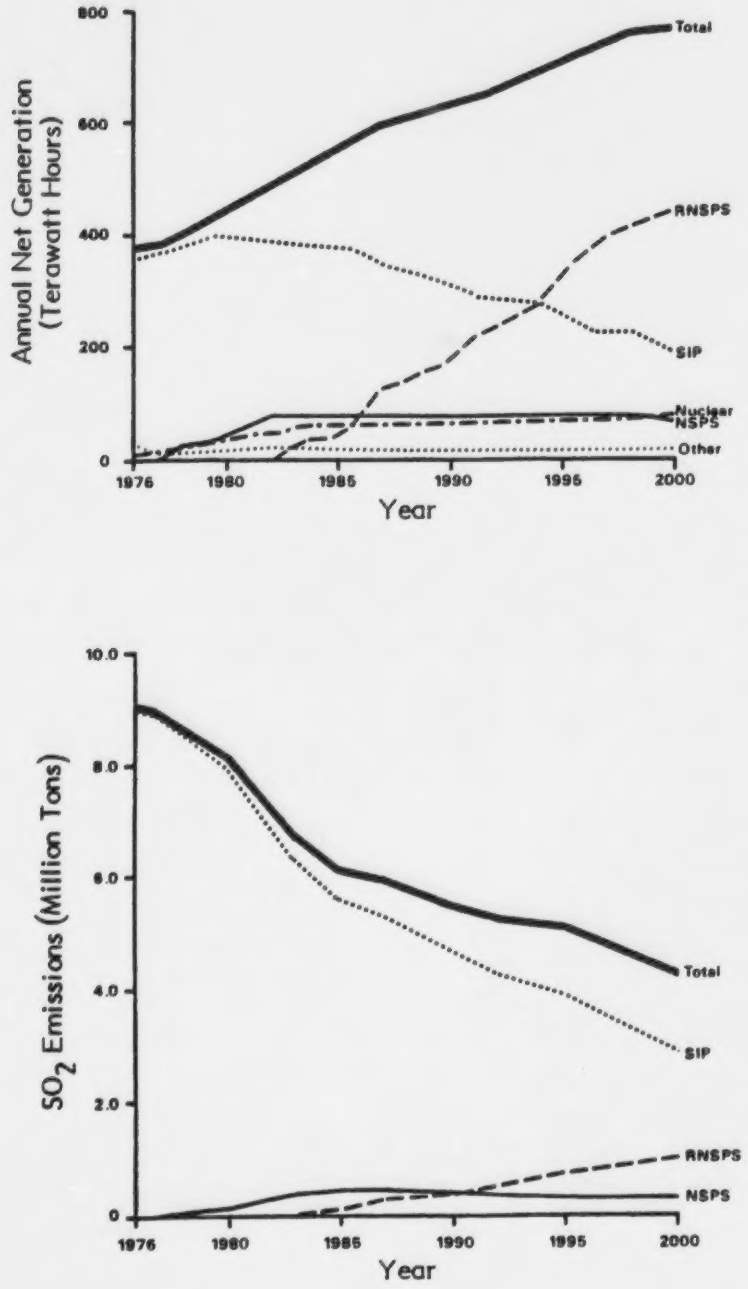
Scenario 2d differs from the base-case Scenario 2 in that it assumes no SIP compliance. Comparisons of Scenarios 2 and 2d show the emission reductions and costs associated with achieving compliance by 1985 with expected State Implementation Plans for SO_2 and particulates.

Without SIP compliance (Scenario 2d), SO_2 emissions will increase from 8.9 million tons in 1976 to 10.1 million tons in 1985. If SIP compliance occurs by 1985 (Scenario 2), SO_2 emissions will decrease to about 6.1 million tons per year – a reduction of 32 percent below 1976 levels and a reduction of 40 percent below the 1985 levels projected in the absence of compliance. Assuming SIP compliance, a 51 percent reduction in SO_2 emissions below 1976 levels could be achieved by 2000 if coal units were retired from service at 35 years of age after 1985. These projections are illustrated in Figure 1-4.

After SIP compliance occurs, SO_2 emission levels will be determined principally by the number of remaining SIP plants. The dashed lines in Figure 1-4 illustrate

Figure I-3

Annual Electric Utility Net Generation and Coal-Plant SO_2 Emissions in the ORBES Counties under Scenario 2 (Base Case with SIP Compliance)



EFFECTS OF BASE-CASE SIP COMPLIANCE FOR SO_2 AND PARTICULATES ON COSTS AND EMISSIONS IN THE ORBES REGION
(SCENARIO 2 VERSUS SCENARIO 2d)

Figure 1-4

Effects on Annual Electric Utility Coal-Plant SO_2 Emissions

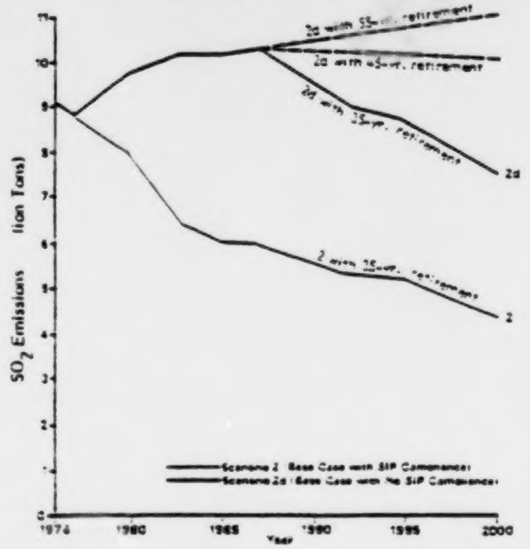


Figure 1-5

Effects on Cumulative Electric Utility FGD Capital Costs and Percentage SO_2 Emission Reductions

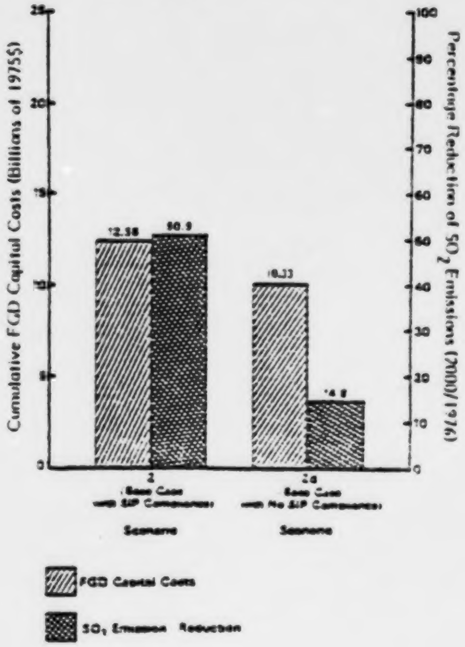
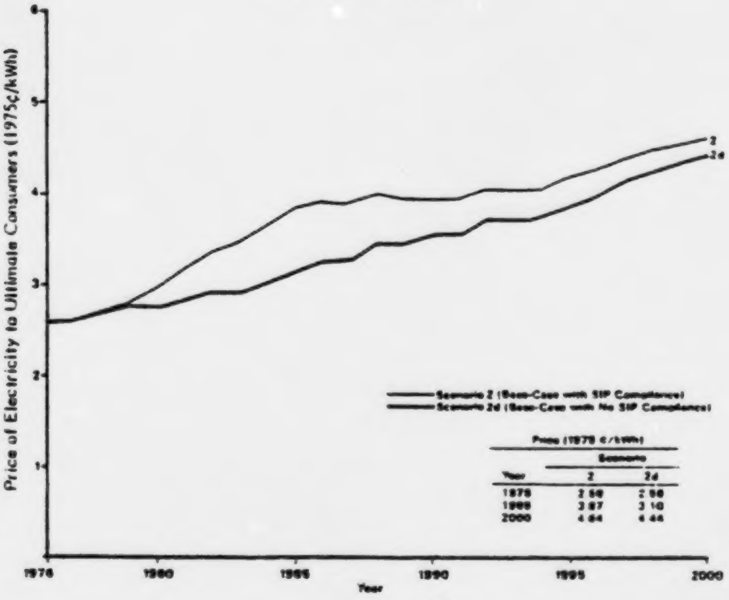


Figure 1-6

Effects on Electricity Prices



Price (1975 ¢/kWh)

	Scenario	
Year	2	2d
1976	2.58	2.58
1985	3.87	3.10
2000	4.64	4.44

the significance of generating-unit lifetimes. As the figure shows, 45- or 55-year lifetimes for coal-fired generating units would keep ORBES county SO_2 emissions level or even increase them after 1985, depending on the amount of new capacity added. In contrast, a 35-year unit lifetime (after which the unit would be retired from service) would lead to SO_2 emission reductions. Assuming SIP compliance by 1985, the magnitude of SO_2 emission reductions in the 1990s will be directly related to the expected retirement rates of existing SIP plants.

The difference in cumulative FGD costs shown in Figure 1-5 indicates that it will cost about $2 billion in the ORBES area to retrofit flue gas desulfurization devices (FGD), which will be installed on less than half the existing capacity to meet the expected SIPs considered in this study. Most plants will comply with SIPs by switching to coals lower in sulfur than those presently used, or by switching to cleaned coals. The total capital costs of particulate controls on SIP units will approach $3.3 billion in the ORBES area, averaging about $47 per kilowatt for retrofitted electrostatic precipitators (ESPs).

Figure 1-6 shows that, without SIP compliance, real electricity prices between 1976 and 1985 will rise at the rate of about 2.1 percent per year (i.e., 2.1 percent per year measured in constant 1975 dollars). From 1985 to 2000 — again, without SIP compliance — the real prices will increase annually by 2.4 percent. With SIP compliance, on the other hand, real electricity prices between 1976 and 1985 will grow by 4.6 percent per year. Thus, in 1985 consumers could pay as much as 0.77¢ (or 25 percent) more per kilowatt-hour to cover the costs of SIP SO_2 and particulate control. By the year 2000, however, the SIP pollution control devices will be paid for, so that the price difference between compliance and noncompliance will be less (about 0.20¢/kWh, which amounts to an increment of 5 percent for SIP compliance).

For comparison, the 1976 price of electricity in the ORBES area was calculated to be 2.58¢/kWh in 1975 dollars.

Thus, over the period from 1976 to 2000, complying with expected SIP SO_2 and particulate limits will increase cumulative revenues required from ultimate consumers by about 10 percent over the case with no compliance. Emissions in the year 2000 will be 42 percent lower for SO_2, and 82 percent lower for particulates, under the base-case scenario with SIP compliance versus noncompliance.

Sensitivity of Costs, SO_2 Emissions, and Electricity Prices to Generating-Unit Lifetimes

(Scenario 7 versus Scenario 7b)

ORBES county SO_2 emission levels in the 1990s and beyond will depend to a significant degree on the rate at which existing SIP coal units are retired. A ten-year increase in expected generating-unit lifetimes (from 35 to 45 years) could result in a 29 percent (1.4 million ton) increase in annual SO_2 emissions in the year 2000.

Under higher rates of growth in electricity demand and a 35-year expected unit lifetime (Scenario 7b), SO_2 emissions will decrease after 1985 because of retirements, dropping to about 4.7 million tons in the year 2000. However, under the same higher growth rates in demand but an expected unit lifetime of 45 years (Scenario 7), SO_2 emissions will persist at about the same level (6.1 million tons per year) between 1985 and 2000. (See Figure 1-7.) The decrease in emissions prior to 1985 under both scenarios will come almost entirely from SIP compliance, since the coal-unit retirements occurring before 1985 will be negligible.

Capital costs will decrease under a 45-year unit life, since less new capacity will be needed to replace retired units: about 14 fewer gigawatts of additional capacity will be required by the year 2000. Under high demand growth and a 35-year unit life (Scenario 7b) versus high demand growth and a 45-year life (Scenario 7), total cumulative capital costs for new units coming on line over the 1976-2000 period amount to about \$100 billion versus \$90 billion, capital costs for FGDs total about \$19 billion versus \$17 billion, and capital costs for

SENSITIVITY OF COSTS, SO_2 EMISSIONS, AND ELECTRICITY PRICES TO GENERATING-UNIT LIFETIMES IN THE ORBES COUNTIES (SCENARIO 7 VERSUS SCENARIO 7b)

Figure 1-7

Sensitivity of Annual Electric Utility Coal-Plant SO_2 Emissions

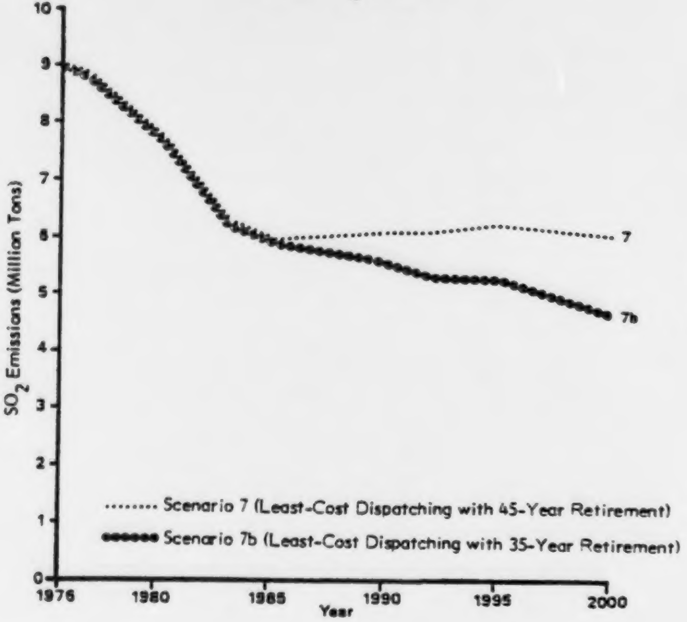


Figure 1-8

Sensitivity of Cumulative Capital Costs (1976-2000) for New Coal Generating Capacity and Pollution Control Equipment to SIP Plant Retirement Age

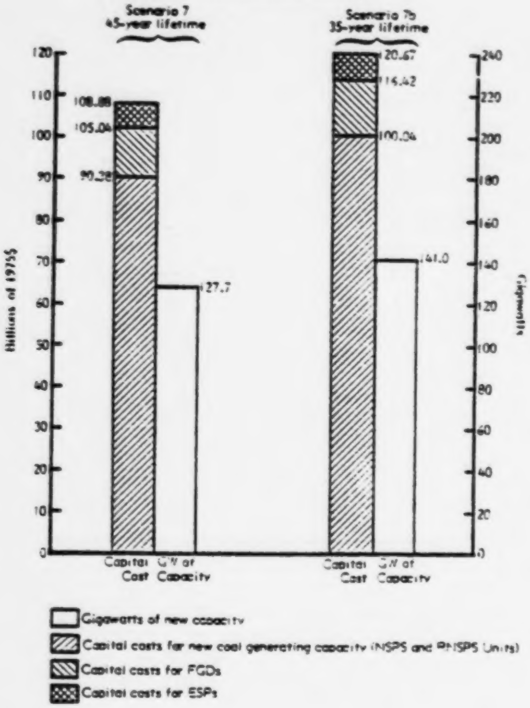
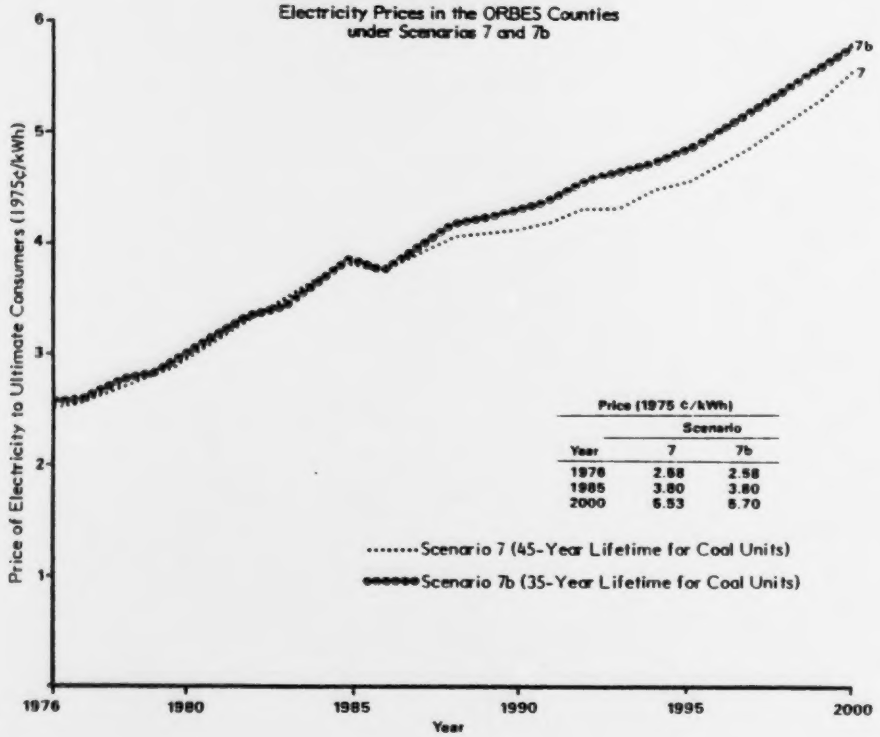


Figure 1-9

Electricity Prices in the ORBES Counties under Scenarios 7 and 7b



Price (1975 ¢/kWh)

Year	Scenario 7	Scenario 7b
1976	2.58	2.58
1985	3.80	3.80
2000	5.53	5.70

electrostatic precipitators (ESPs) total \$7.6 billion versus \$7.1 billion.* (See Figure 1-8.)**

The decreased costs of a 45-year unit retirement age are also reflected in the real price of electricity after 1986. In the year 2000, the price of electricity comes to 5.70¢/kWh under a 35-year unit life, but to 5.53¢/kWh under a 45-year life. (See Figure 1-9.) Cumulative revenues required from ultimate consumers over 1976-2000 decrease from \$639 to \$617 billion, a 3.5 percent reduction.

Sensitivity of Costs, SO_2 Emissions, and Electricity Prices to SIP Limits

(Scenarios 2, 2d, and 1)

We have already evaluated the effects of SIP compliance by comparing Scenario 2, the base case with compliance, with Scenario 2d, the base case without compliance. Now we compare Scenario 1 with Scenarios 2 and 2d. In Scenario 1, stricter SIP SO_2 limits are applied. Assuming SIP compliance, the stricter limits compared with the base-case limits result in a 20 percent greater decrease in SO_2 emissions from 1976 to the year 2000. Percentage changes in electricity prices are less dramatic. Required revenues over the 1976-2000 period increase by about 4 percent over the base case.

Under the base case in the year 2000, SO_2 emissions are reduced 51 percent below 1976 levels; under stricter SIPs, SO_2 emissions are reduced 71 percent below 1976 levels. The stricter SIPs analyzed averaged about 1.3 lb $SO_2/10^6$ Btu over all the ORBES counties, while the base-case expected SIPs averaged 3.3 lb $SO_2/10^6$ Btu. Figure 1-10 compares annual SO_2 emissions under the three SIP scenarios.

---

* Again, all costs and prices given in this report are in constant 1975 dollars.

** Note also that the data in Figure 1-8 represent totals for new pollution controls only; the base-case costs of retrofitted FGD amount to \$2.12 billion for 26 GW, and the base-case costs of retrofitted ESPs amount to \$3.3 billion for 69.5 GW. Under the base-case SIPs, most SIP plants will burn complying coals rather than install FGD.

SENSITIVITY OF COSTS, SO_2 EMISSIONS, AND ELECTRICITY PRICES TO ALTERNATIVE SIP LIMITS AND COMPLIANCE STRATEGIES IN THE ORBES COUNTIES (SCENARIOS 2, 2d, AND 1)

Figure 1-10

Sensitivity of Annual Electric Utility Coal-Plant SO_2 Emissions

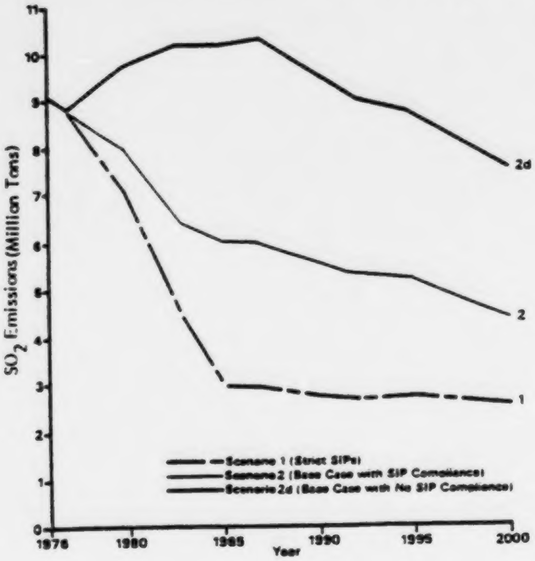


Figure 1-11

Sensitivity of Cumulative FGD Capital Costs (1976-2000) and SO_2 Emissions in 2000 (Percentage Change from Base-Case SIP Compliance)

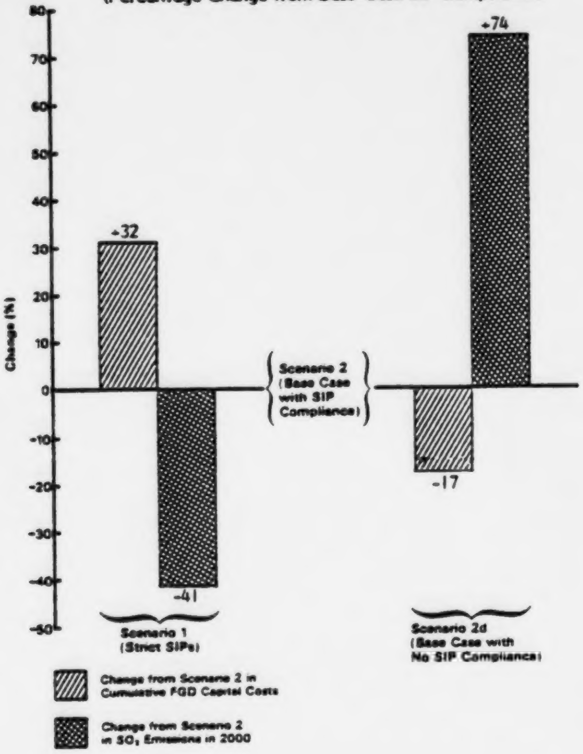
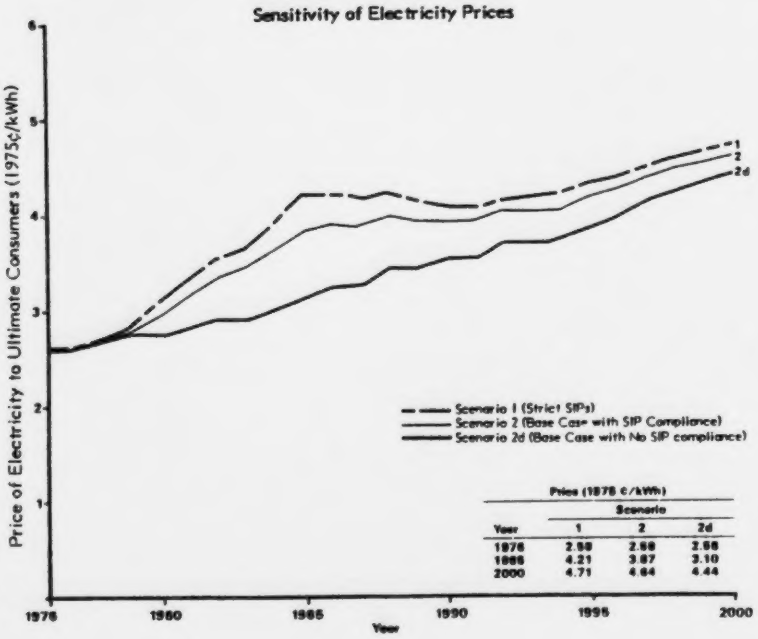


Figure 1-12

Sensitivity of Electricity Prices



Price (1975 ¢/kWh)

Year	Scenario 1	Scenario 2	Scenario 2d
1976	2.58	2.58	2.58
1985	4.21	3.87	3.10
2000	4.71	4.64	4.44

Compared with the base case, compliance with stricter SIPs requires retrofitting an additional 33 GW of capacity with FGD, at a cost of \$3.9 billion, resulting in an incremental capital cost for FGD of nearly \$117/kW. Percentage changes in cumulative FGD capital costs (1976-2000) and SO_2 emissions in 2000 under the stricter SIPs compared with the base case are shown in Figure 1-11.

The implementation of these stricter SIPs raises the price of electricity to 4.21¢/kWh in 1985 — 9 percent above the base case with expected SIPs, and 36 percent above the noncompliance case (see Figure 1-12). Required revenues from ultimate consumers over the 1976-2000 period increase by about 4 percent over the base case.

Sensitivity of Costs, SO_2 Emissions, and Prices to Rates of Growth in Electricity Demand

(Scenarios 4, 2, and 7b)

The effects of different rates of growth in electricity demand were examined. These annual rates, over the period from 1976 through 2000, averaged 1.6 percent (Scenario 4), 2.8 percent (Scenario 2), and 3.7 percent (Scenario 7b), as specified by the ORBES Core Team. The rates were not uniform over time and were generally lower after 1985. It was found that regional SO_2 emissions are not highly sensitive to future rates of growth in electricity demand.

By the year 2000, higher demand growth and a 35-year life for coal units (Scenario 7b) increases regional SO_2 emissions by 8 percent over the base case (an increment of 0.36 million tons per year), while low growth (Scenario 4) reduces emissions by 10 percent (a decrease of 0.42 million tons per year). (See Figure 1-13.) Under all three scenarios, the older SIP units produce the bulk of the emissions.

Under low growth, overall SO_2 emissions are reduced primarily by the deferral of newer, cleaner units. Under high growth, emissions will increase. However, since new plants are required to remove 85 to 90 percent of their potential SO_2 emissions, it will take five or six new plants to produce the total SO_2 emissions generated by an average older plant.

SENSITIVITY OF COSTS, SO_2 EMISSIONS, AND PRICE TO RATES OF GROWTH IN ELECTRICITY DEMAND IN THE ORBES COUNTIES (SCENARIOS 4, 2, AND 7b)

Figure 1-13

Sensitivity of Annual Electric Utility Coal-Plant SO_2 Emissions

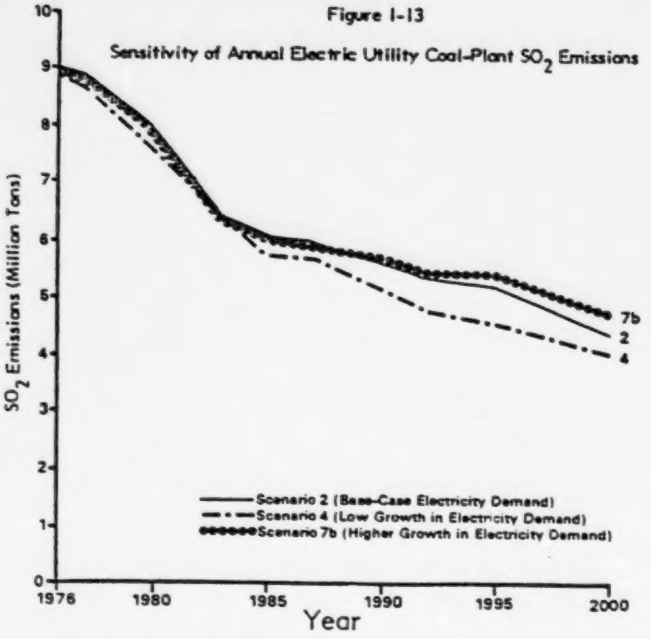
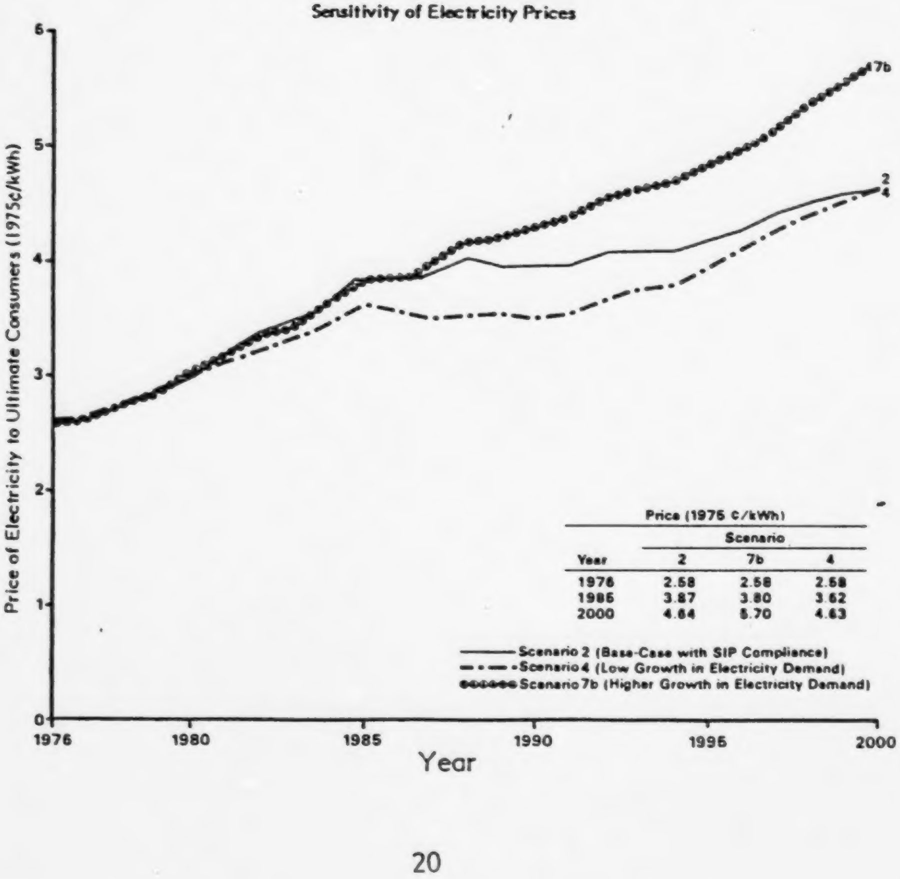


Figure 1-14

Sensitivity of Electricity Prices



Price (1975 ¢/kWh)

Year	Scenario 2	Scenario 7b	Scenario 4
1976	2.58	2.58	2.58
1985	3.87	3.80	3.62
2000	4.64	5.70	4.63

Capital costs for coal-fired generating capacity coming on line in the ORBES counties over the period from 1976 through 2000 are shown in Table 1-1 for three scenarios. These cumulative capital costs depend significantly on rates of growth in electricity demand.

Capital costs for pollution control equipment on new units (ESPs and FGDs) amount to an additional \$8.3 billion under Scenario 4, \$13.4 billion under Scenario 2, and \$20.6 billion under Scenario 7b. FGDs on new units will cost about \$124/kW; and new ESPs will cost about \$31/kW. Retrofitted FGDs will average about \$81/kW (to meet less stringent removal requirements), while retrofitted ESPs will average about \$47/kW.

Table 1-1

Cumulative Capital Costs of New Coal-Fired Generating Capacity through 2000

	GW of New Installed Capacity, 1976-2000*	Cumulative Capital Costs (Billions of 1975$)	Average $/kW
Scenario 4	59.0	40.9	694
Scenario 2	95.5	67.0	702
Scenario 7b	141.0	100.0	710

* Before capacity penalties for pollution control.

These capital costs, as well as operating, maintenance, and investment costs, change the revenue requirements of utilities. This in turn influences the price of electricity to ultimate consumers. Under moderate demand growth (Scenario 2) and high demand growth (Scenario 7b), electricity prices increase from 2.58¢/kWh in 1976 to 4.64¢/kWh and 5.70¢/kWh in 2000, respectively. Under lower demand growth (Scenario 4), the price of electricity in 1985 is lower by 6 percent (0.25¢/kWh) than the base-case projected price. Between 1985 and

1995, the price difference between the low and moderate growth cases is as much as 0.5¢/kWh. However, after 1995 the price of electricity rises more rapidly under the low growth case, since specified retirements and demand growth after 1995 are nearly the same as in the moderate growth scenario. (See Figure 1-14.)

Cumulative 1976-2000 revenue requirements from the ultimate consumers of electricity generated in the ORBES counties are projected at $638.5 billion under high growth, $525.3 billion under moderate growth, and $389.7 billion under low growth. Compared with the base case of moderate growth in electricity demand, high growth increases cumulative revenue requirements by 22 percent while low growth reduces cumulative revenue requirements by 26 percent.

Sensitivity of Costs, Emissions, and Prices to System Dispatching Criteria

(Scenario 7a versus Scenario 7)

Dispatching coal-fired plants in a utility system under a criterion of least emissions (Scenario 7a) rather than least cost (Scenario 7) may reduce emissions in the ORBES counties significantly as cleaner plants come on line after 1985. The increase in electricity prices would be relatively small. Potential effects on system reliability, if any, should be examined.

Typically, generating units are loaded in order of increasing costs – baseload units are cheaper to operate and therefore are used to generate more electricity. Scenario 7a was designed to test the sensitivity of costs (measured in the form of electricity prices to ultimate consumers) and emissions to a least-emissions dispatching criterion for coal-fired units only. All other units were projected to operate on the usual least-cost basis. Under the least-emissions criterion, the units emitting the most (on a per Btu basis) would be loaded last.

Because of the preponderance of SIP-regulated capacity in the ORBES area, a least-emissions dispatching strategy to meet a specified consumer demand reduces overall generation and emissions within the ORBES counties by increasing the operation of newer, cleaner plants in and outside the area. SO_2 emissions in the ORBES counties in 2000 under Scenario 7a could decrease to about 3.3 million tons per year. This would be accomplished by increasing the share of the load for newer coal plants (subject to the 1979 RNSPS and 1971 NSPS) while reducing the load for SIP plants. Percentage SO_2 emission reductions would be greater than the proportional reduction in load, since the dirtiest units would come last in the new dispatch order.

The major additional costs of a least-emissions dispatching strategy are due to increased plant operating costs — principally for increased operation of pollution control devices and the added costs of burning greater quantities of more expensive cleaned or lower-sulfur coals. It was assumed that no diminution of plant reliability or availability would occur and that grid characteristics would permit this change in dispatching criteria. To the extent that these assumptions are not valid, lesser emission reductions at reduced costs would occur.

It should be noted that the efficacy of the least-emissions strategy increases the greater the number of new generating plants that can be baseloaded. In the ORBES counties, coal units built after 1985 will emit SO_2 at an average rate that is about five times less than that of complying SIP plants (0.6 lb $SO_2/10^6$ Btu for RNSPS plants, versus an average of 3.3 lb $SO_2/10^6$ Btu for SIP plants).

The overall price of electricity in the ORBES counties rises by 0.1¢/kWh under a least-emissions dispatching strategy. This increment represents less than 2 percent of the projected price in the year 2000.

An Electricity Demand Forecast for the ORBES Counties

For the preceding scenarios, electricity-generation totals in the ORBES counties for 1985 and 2000 were specified by the Core Team. Because of changes in the price of electricity, electricity demand growth has decreased in recent years. On the basis of USM price projections to 1985, econometric methods were used to arrive at an independent forecast of a 3.7 percent per year average growth in electricity demand in the ORBES counties between 1976 and 1985.

Using an assumed long-run price elasticity for electricity demand of -0.79 (which means that a 1 percent rise in the price of electricity will reduce demand by 0.79 percent), an income elasticity of +0.97, and projected USM electricity prices, we find that the rate of growth in electricity demand in the ORBES counties will average about 3.7 percent per year between 1976 and 1985. The rising prices assumed in the scenarios examined in this study contribute to the reductions in historical rates of growth in electricity demand in the period before 1985. However, the forecasts suggest that, if the rates of growth in electricity demand in the ORBES counties are to be significantly reduced after 1985, changes in factors other than the price of electricity — such as altered consumer habits, more energy-efficient homes, or improved industrial processes — will have to occur. Indeed some of these changes, which are not reflected in this demand forecast, may already be occurring.

2. THE STUDY – BACKGROUND, ISSUES, AND SCENARIOS

2.1 Background: The Utility Simulation Model and Overview of Utilities in the ORBES Counties

The electric utility industry plays a significant role in the United States as an energy supplier and fuel consumer. The energy, economic, and environmental impacts of its activities are often complex, and one region of the nation in which these impacts are particularly important is the six-state area of concern in the Ohio River Basin Energy Study (ORBES).* In support of this study, the Utility Simulation Model (USM) has been applied to examine alternative scenarios for electric utility development in the ORBES counties over the period from 1976 through 2000. This detailed model has been used in order to provide a consistent framework for quantitative analysis and for the investigation of key factors and policies.

The USM, which consists of a number of interconnected computer modules and data sets, simulates utility decisions for system planning and operation and calculates the implications of these decisions for utility finance, energy consumption, and the environment.** In order to project emissions, costs, and other effects at the required level of detail, the model considers generating-unit sites located in each county where electricity is produced, fuel and water are consumed, solid wastes are generated, and pollutants are released. (Comparison of the model results with historical data is discussed in Appendix A.) Since utilities operate as integrated systems, the model simulates the joint operation (e.g., least-cost dispatching) of various types of generating units and capacity classes owned by all utilities based within a state.

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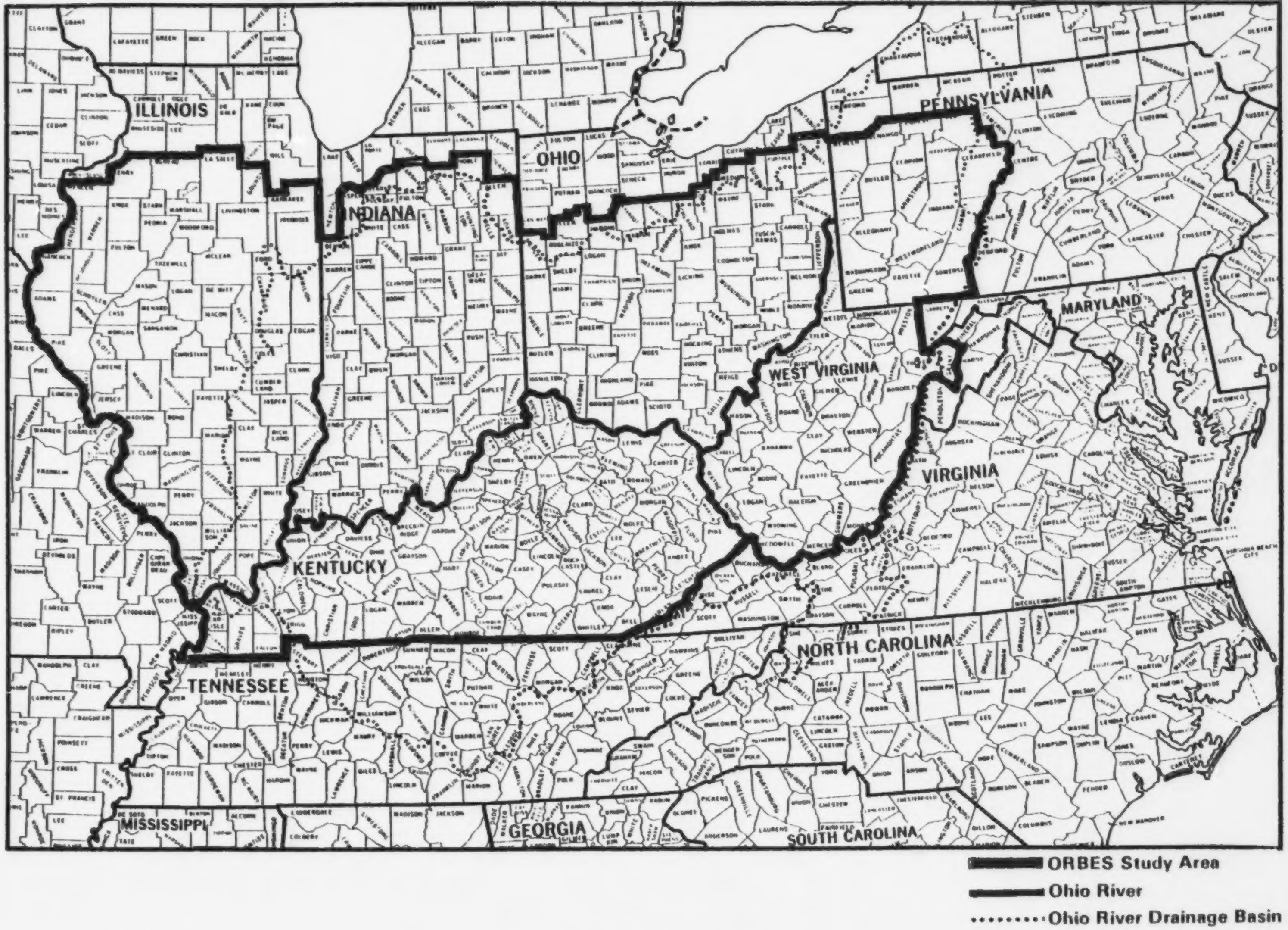
* The six ORBES states are Pennsylvania, Ohio, Indiana, Illinois, West Virginia, and Kentucky. The ORBES study area embraces large portions of these states, as shown in Figure 2-1.

** Teknekron Research, Inc., Utility Simulation Model Documentation, vol. 1, Overview, Model Outputs, and Analytic Structure, R-009-EPA-79, Prepared for U.S. Environmental Protection Agency, Office of Research and Development, Office of Energy, Minerals, and Industry (Washington, D.C., July 1979).

Figure 2-1
Region of Concern in Phase II of the Ohio River Basin Energy Study


ILLINOIS
INDIANA
OHIO
PENNSYLVANIA
MARYLAND
WEST VIRGINIA
VIRGINIA
KENTUCKY
TENNESSEE
NORTH CAROLINA
SOUTH CAROLINA
GEORGIA
MISSISSIPPI
ORBES Study Area
Ohio River
Ohio River Drainage Basin

In this study, the operations of the investor-owned utilities in each state were simulated as if these utilities were an integrated firm (a "state-firm"). Similarly, operations of the publicly owned utilities in each state were simulated as if these too were integrated. Thus, the results presented here assume a uniformity of corporate planning and state regulation for the utilities in each state. It should be noted that some generating units owned by ORBES utilities in the ORBES counties are sited outside the ORBES area or across state boundaries within the region. All these units were accounted for in the simulation, and the actual ownership of each unit is reflected in the model. Further, the data bases used in projecting the future operations of the ORBES utilities incorporated announced utility plans.

The utilities in the ORBES area vary in size and institutional structure. Fifty-five utilities owned over 80,000 megawatts of generating capacity in the ORBES counties at the end of 1976.* The operation of this capacity was characterized by the approximate statistics listed in Table 2-1.

Table 2-1

Capacity, Generation, and SO_2 Emissions Mix in the ORBES Counties — 1976

	Capacity GW (%)	Generation TWh (%)	SO_2 Million Tons (%)
Nuclear	2.1 (2.6)	10.0 (2.6)	0 (0)
Coal	72.7 (89.7)	363.1 (95.6)	8.94 (99.9)
Oil	2.5 (3.1)	2.3 (0.6)	0.01 (0.1)
Other (including hydro, pumped hydro, combustion turbine, and internal combustion)	3.7 (4.6)	4.5 (1.2)	0.002 +
TOTAL	81.1 (100)	379.9 (100)	8.95 (100)

+ Less than 0.1%.

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* Capacity and generation data are extracted from the National Electric Reliability Council's report to the Federal Power Commission, FPC Form 383-3, April 1, 1978. Emissions data are extracted from the USM simulation for Scenario 2.

In 1976, investor-owned utilities accounted for approximately 89 percent (or 67,403 MW) of the ORBES counties' total steam electric generating capacity (more than 76,000 MW). More than two-thirds of the investor-owned amount was owned or controlled by the following holding companies and power pools:

	MW Owned in ORBES*	Percentage of Investor-owned Capacity in ORBES
American Electric Power	13,554	20.1
Allegheny Power System	6,316	9.4
General Public Utilities	5,405	8.0
Kentucky-Indiana Pool Planning and Operating Agreement (KIP)	8,468	12.6
Central Area Power Coordination Group (CAPCO)	6,610	9.8
Illinois-Missouri Power Pool	5,715	8.5
TOTAL	46,068	68.4

Of the remaining 8,600 MW of capacity owned by non-investor-owned utilities, almost half (48 percent) was owned by the Tennessee Valley Authority.

2.2 Issues in the ORBES Counties

Several key issues were chosen for analysis in this study:

- How sensitive are ORBES county emissions to compliance with State Implementation Plan emission regulations for coal-fired power plants?
- How will emissions in the ORBES counties be affected if there is no compliance with power-plant SIP emission limits?

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* Note: This list does not include 2,010 MW owned by Columbus and Southern Electric Company of Ohio.

- What are the costs of achieving emission reductions under the assumed SIP emission limits?
- How sensitive are ORBES county emissions and electricity costs to stricter SIP emission regulations?
- How do projected high and low rates of growth in electricity demand affect future emissions and costs in the ORBES counties?
- What effect do assumed generating-unit lifetimes have on ORBES county emissions and electricity costs?
- What environmental and economic impacts might result from dispatching coal-fired units on the basis of a "least emissions" criterion in contrast to the usual "least cost" criterion?
- How will these various alternatives affect air quality in the ORBES counties?

These issues were synthesized into scenarios to be examined using the USM. By comparing the results of scenarios where just one specific assumption or set of assumptions was changed, the difference can be taken to represent the effect of the policy change of interest. The results are not intended to predict a "most likely" future, but rather to compare and contrast alternate policies.

2.3 The Scenarios — Their Commonalities and Differences

The reader is referred to previous reports for a description of the Utility Simulation Model and its applications.* In one of these reports, Utility Simulation Model Documentation, we review common model inputs normally specified by the user. In addition, the supporting data base is documented and algorithms are explained.

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* Teknekron Research, Inc., Utility Simulation Model Documentation, op. cit. See also Teknekron Research, Inc., Review of New Source Performance Standards for Coal-Fired Utility Boilers, Phase Three Final Report, Sensitivity Studies for Selection of a Revised Standard, EPA-600/7-79-215 (Washington, D.C.: U.S. Environmental Protection Agency, Office of Research and Development, Office of Environmental Engineering and Technology, December 1979).

An important feature of the USM is its adaptability to changing input assumptions and specifications. For this study, seven scenarios were specified by the ORBES Core Team and then implemented; implementation was accomplished by modifying the data bases and computer codes.

All the ORBES scenarios shared certain assumptions and specifications. A number of specific, significant parameters and data sets were then varied to obtain the different scenario projections. Here we review the significant parameters influencing the projections.

Steam-Unit Retirements. Fossil steam units were assumed to be retired according to the utility's announced retirement schedule or, in the absence of an announced retirement date, 35 years after the date of coming on line.* The end-of-simulation results (roughly the period 1990-2000) turned out to be sensitive to this assumption. It was apparent that longer coal-unit lifetimes for SIP-regulated units would lead to higher emissions in 2000 and to different costs. Therefore, the assumption of a longer (45-year) unit lifetime was applied in two of the scenarios. And, indeed, as new generating plants become more expensive, it may be that utilities will prefer to extend the lifetimes of their existing units where it is feasible to do so. It should also be noted that capacity additions and retirement projections were carried out to the year 2010 in order to account for the costs of additions paid prior to 2000.

Electricity Demand Growth. "Target" generation figures for the ORBES area were specified by the Core Team by applying an input/output model of economic activity. The USM was then calibrated to this target, by scenario, by scaling yearly growth estimates to obtain the required total generation in all ORBES counties for 1985 and 2000. In order to keep the model's national results consistent, growth rates outside the ORBES counties were also scaled. The growth rates prior to 1985 for most scenarios were based on the Core Team's interpretation of announced utility plans to 1985. Electricity generation in the year 2000 was also specified in most cases by the ORBES input/output model. See Appendix A for a discussion of this calibration effort.

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* Gary L. Fowler, University of Illinois at Chicago Circle; Robert E. Bailey, the Ohio State University; J.C. Randolph, Indiana University; and Steven I. Gordon, the Ohio State University, The Ohio River Basin Energy Facility Siting Model, Ohio River Basin Energy Study, Phase II, vol. I, Grant Nos. EPA R805588, R805589, and R805609 and Subcontract under Prime Contract EPA R805588 (forthcoming).

Capacity Additions. Although the USM is capable of simulating a number of alternative generating technologies, the scenarios specified for this analysis assumed that future generation in the ORBES counties would rely predominantly on coal. No new nuclear units were added beyond those already announced by utilities. Nonconventional generating technologies were not included in these projections.

Individual Electrical Generating Units. The USM file of individual generating units contains data pertaining to each existing and announced steam generating unit in the contiguous United States. This file is kept up to date with information from the NERC Coordinated Bulk Power Supply reports and other sources. The ORBES Core Team also developed a list of announced capacity,* and this list agreed with the USM file for units existing in 1976. The list of generating units was modified to match ORBES specifications as follows:

- ORBES siting specifications were used for planned units in ORBES counties and for post-1987 scenario unit additions (i.e., units not yet planned by utilities)

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* See memorandum from Gary L. Fowler to the ORBES Core Team, June 20, 1979, in which reference is made to Steven D. Jansen's "Electrical Generating Unit Inventory, 1976-1986: Illinois, Indiana, Kentucky, Ohio, Pennsylvania and West Virginia" (November 1978). See also Gary L. Fowler, University of Illinois at Chicago Circle; Robert E. Bailey, the Ohio State University; J.C. Randolph, Indiana University; and Steven I. Gordon, the Ohio State University, The Ohio River Basin Energy Facility Siting Model: List of Sites and On-Line Dates for ORBES Scenarios, Ohio River Basin Energy Study, Phase II, vol. II, Grant Nos. EPA R805588, R805589, and R805609 (forthcoming).

- ORBES-specified units not in the USM file were also included

In a few cases, on-line dates and the existence of several units specified by ORBES were either superseded by April 1, 1979, NERC on-line estimates or were verified by telephone interviews with utility staff members.

Historical Coal Assignments. For all ORBES county coal-fired units governed by SIPs, the simulation began by assuming the use of historical coals — that is, coals with the average characteristics of those used in 1976. (See Table B-12 in Appendix B and also Table 2-4.) Hence, the emissions projected by the model for 1976 closely agree with historical emissions data from other sources.* General characteristics of the coals assigned to units governed by the New Source Performance Standards or by revised SIPs are also discussed in Appendix B. The ORBES Core Team specified that regionally produced coals would be used.

Push to Coal. For all scenarios analyzed in this report, the ORBES Core Team assumed that any new unit coming on line during the 1988-2000 period would be a 650-MW(e) coal-fired facility. This rule was superseded only by announced utility plans.

The seven ORBES scenarios, described by their most salient characteristics, include:

- Scenario 1 — Strict siting and stricter-than-expected SIPs
- Scenario 2 — The base case, with expected SIPs and SIP compliance by 1984
- Scenario 2d — The base case with no SIP compliance
- Scenario 4 — Low growth in electricity demand
- Scenario 7 — High growth in electricity demand, least-cost dispatching, and a 45-year coal unit lifetime

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* See Appendix A for a discussion of USM calibration.

- Scenario 7a — Same as 7, but with least-emissions dispatching
- Scenario 7b — Same as 7, but with a 35-year coal unit lifetime

Each scenario is described in detail below.

Scenario 1 — Strict Siting and Stricter-than-Expected SIP Emission Regulations

Demand. The USM DEMAND module was adjusted to project "target" generation figures determined by the ORBES Core Team. The target figures for Scenario 1 represent the same rate of growth in electricity generation as in the base-case Scenarios 2 and 2d: an average growth rate of 4.0 percent per year between 1976 and 1985, and of 2.1 percent per year from 1985 to 2000, amounting to an average growth rate of 2.8 percent per year over the entire simulation period.*

Capacity Additions. Conventional technologies and predominant use of coal.

Siting. In the siting specifications for this scenario compared with all the others, there is a movement away from the Ohio River main stem, where water is available, to counties in which water may not be as abundant (see Figure 2-2).**

Retirements. As for all the scenarios except 7 and 7a, a mandatory 35-year retirement schedule for coal units is assumed, as specified by the Core Team.

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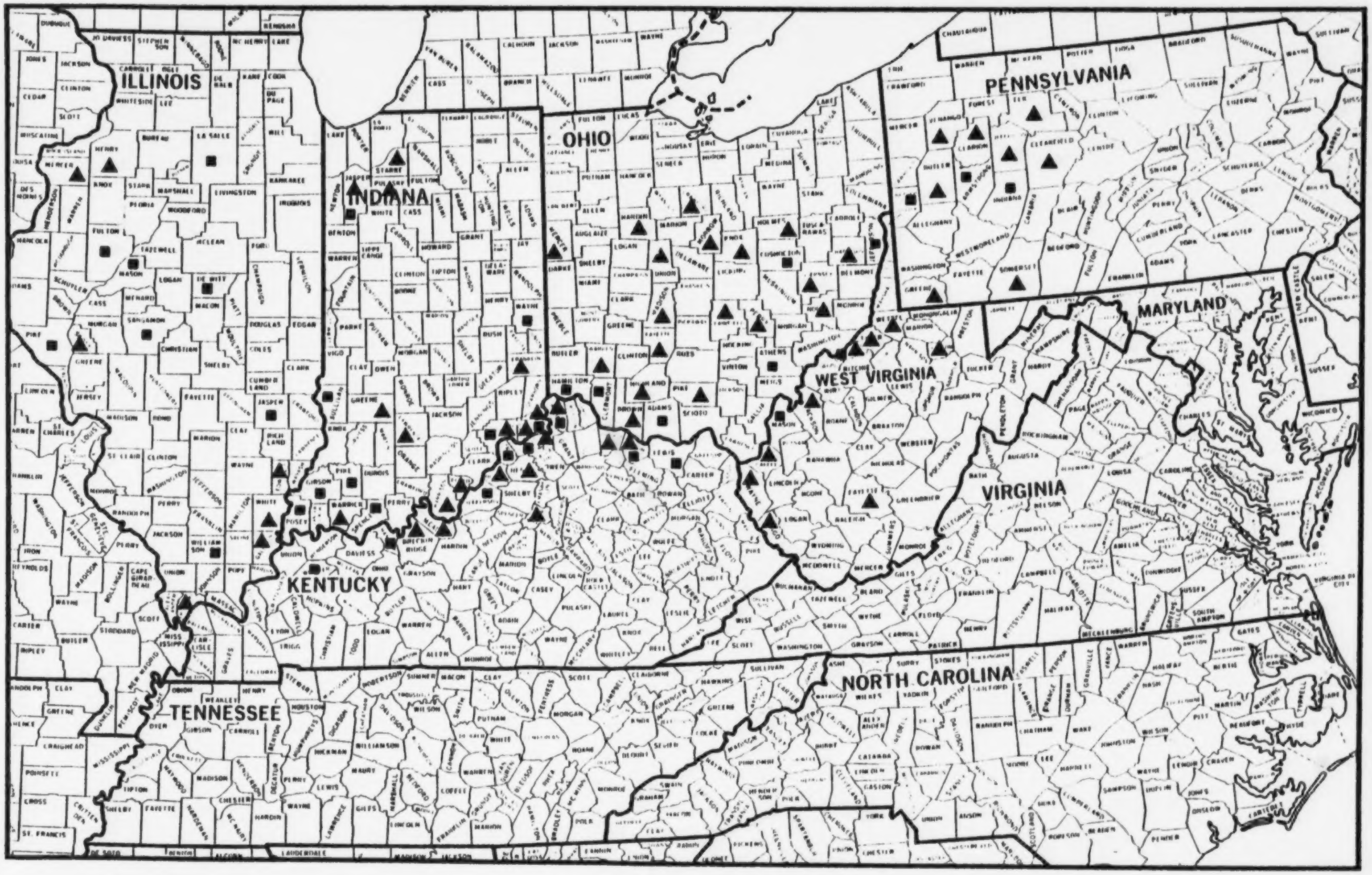
* In April 1979, the East Central Area Reliability Council (which represents most of the ORBES area) estimated that the years from 1979 to 1988 would be marked by an annual average peak-demand growth rate of 4.8 percent, down from the previous year's estimate of 5.5 percent. For the years between 1989 and 1998, their projected annual growth rate is 3.8 percent.

** See also Fowler et al., Ohio River Basin Energy Facility Siting Model, vols. I and II, op. cit.; and memorandum from Gary L. Fowler to the ORBES Core Team, op. cit.

Figure 2-2
Counties with Planned Units or Scenario Additions under ORBES Scenario 1


ILLINOIS
INDIANA
OHIO
PENNSYLVANIA
MARYLAND
WEST VIRGINIA
VIRGINIA
KENTUCKY
TENNESSEE
NORTH CAROLINA
■ Planned units
▲ Scenario additions

Note: Scenario 1 assumes conventional technology and strict environmental controls.

Emission Regulations. All SIP-governed units must comply with SIPs that are more stringent than those expected to be in force in 1985 (see Table 2-2). These stringent SIPs represent levels of control that might be expected in major metropolitan areas in each state under the base case. The federal New Source Performance Standards (NSPS) and the revised New Source Performance Standards (RNSPS) also apply to all later units.

Compliance. SIP units comply with more stringent SIPs over a seven-year schedule, from 1978 to 1984. Except for the more stringent annual emission limits, compliance is the same as for Scenario 2.

Table 2-2

Scenario 1 — Stringent SIP Emission Limitations, by ORBES State (Pounds per Million Btu)

State	Sulfur Dioxide	Oxides of Nitrogen	Total Emitted Particulates
Pennsylvania	0.60	–	0.10
Ohio	1.40	–	0.10
Indiana	1.21	–	0.10
Illinois	1.80	0.75	0.10
West Virginia	1.60	–	0.05
Kentucky	1.21	–	0.20

Dispatch. The economic dispatching of coal-fired units is accomplished through the use of a "least cost" criterion in which variable operating and fuel costs in each year determine the dispatch order. Other classes of generating units are also operated in order of least variable cost.

Scenario 2 — The Base Case with Expected SIPs and Compliance by 1984

Demand. Demand growth rates are the same as those of Scenario 1.

Siting. Sites are concentrated along the main stems of the Ohio River and the Illinois River (see Figure 2-3).*

Retirements. A 35-year retirement schedule is assumed for coal steam units.

Emission Regulations. In this base-case scenario, SIP emission limitations represent 1985 SIP revisions as anticipated in 1979. (See Appendix G for a discussion of the importance of averaging times.) These average annual emission limitations, for rural and urban counties in each state, are listed in Table 2-3. The federal NSPS and RNSPS also apply in this and all other scenarios.

Table 2-3

Base-Case Average SIP Emission Limitations, by ORBES State (Pounds per Million Btu)

State	Sulfur Dioxide		Oxides of Nitrogen		Total Emitted Particulates	
	Urban	Rural	Urban	Rural	Urban	Rural
Pennsylvania	0.60	1.80	—	—	0.100	0.100
Ohio	1.40	4.50	—	—	0.100	0.100
Indiana	1.21	5.00	—	—	0.100	0.100
Illinois	1.80	6.00	0.75	—	0.100	0.100
West Virginia	1.60	3.20	—	—	0.050	0.050
Kentucky	1.21	5.70	—	—	0.200	0.200

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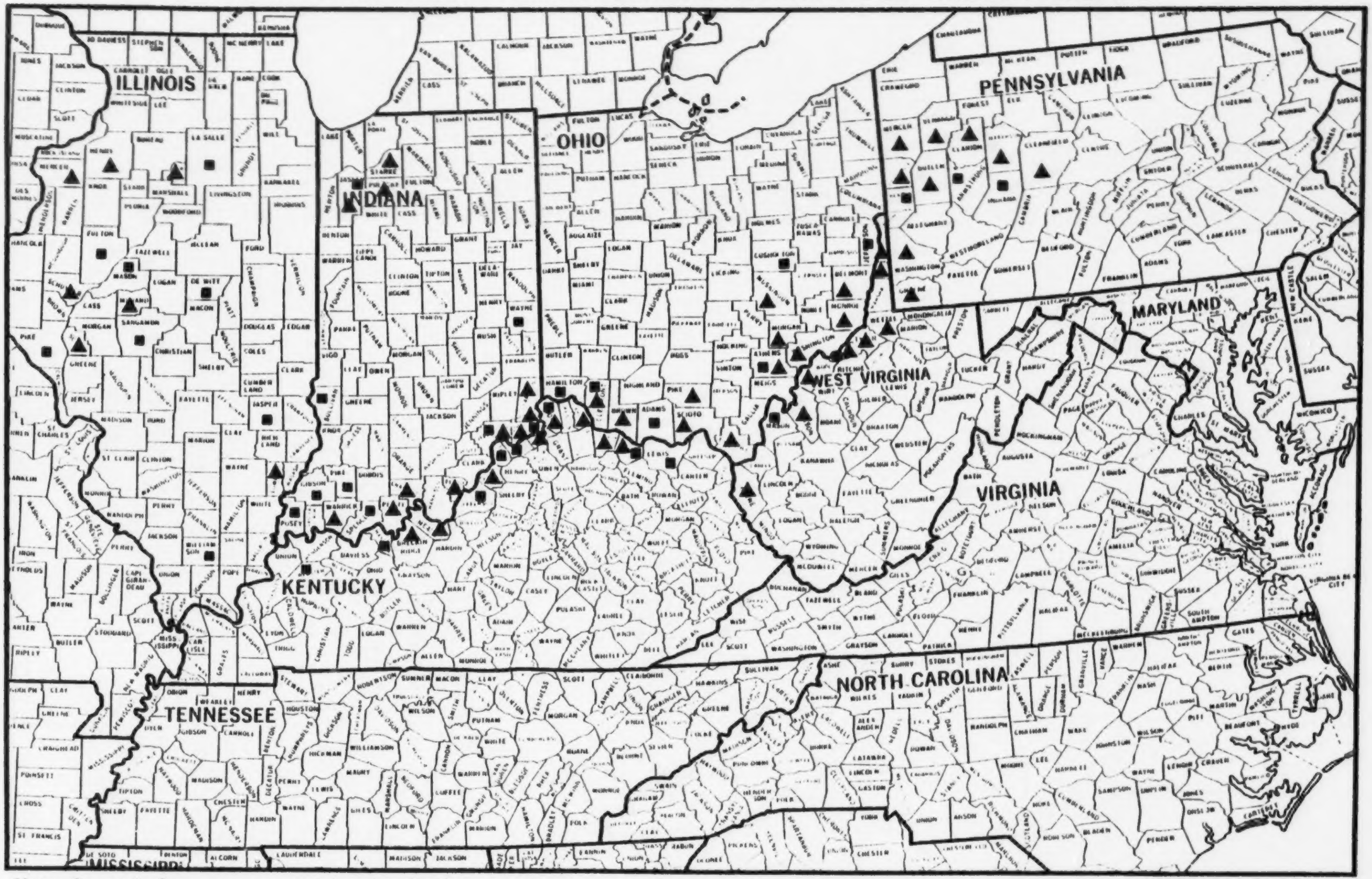
* See also Fowler et al., Ohio River Basin Energy Facility Siting Model, vols. I and II, op .cit.; and memorandum from Gary L. Fowler to the ORBES Core Team, op. cit.

Figure 2-3
Counties with Planned Units or Scenario Additions under ORBES Scenario 2


ILLINOIS
INDIANA
OHIO
PENNSYLVANIA
MARYLAND
WEST VIRGINIA
VIRGINIA
KENTUCKY
TENNESSEE
NORTH CAROLINA
MISSISSIPPI

Note: Scenario 2 assumes conventional technology and base-case environmental controls.

■ Planned units
▲ Scenario additions

Compliance. All SIP-governed units are assumed to come into full compliance over a seven-year period, 1978 through 1984. Initially, each SIP unit begins the simulation burning a historical coal. Then, during one year in the seven-year period, each unit shifts from the historical coal to a "compliance option" coal and, where necessary, retrofits pollution control devices. The SIP compliance strategy is selected on the basis of least cost. Table 2-4 shows the typical characteristics of the historical coals; Table 2-5 shows typical characteristics and the supply regions of potential compliance-option coals. It was assumed that only regionally available coals could be used for SIP compliance. Hence, low-sulfur western coals were not selected. (Appendix B discusses emission standards and utility coal and pollution control options.)

Dispatch. Economic dispatch, as in Scenario 1.

Scenario 2d — The Base Case with No SIP Compliance

Demand. Same as Scenario 2.

Siting. Same as Scenario 2.

Retirements. Same as Scenario 2.

Emission Regulations. In Scenario 2d, the SIP units are simulated in a "non-compliance" mode. Thus, they are never in compliance with the SIP emission standards.

Compliance. Since this is a noncompliance scenario, there is no compliance schedule. The SIP units continue burning historical coals throughout the simulation, and emission controls representing 1976 circumstances are assumed for SIP plants over the entire simulation period.

Dispatch. Economic dispatching, as in preceding scenarios.

Table 2-4

Historical Average Coals for SIP Units in the ORBES Counties

State	Coals for Units in Urban Counties				Coals for Units in Rural Counties			
	Btu/lb	Percent Sulfur	Percent Ash	Price (¢/10^6 Btu)*	Btu/lb	Percent Sulfur	Percent Ash	Price (¢/10^6 Btu)*
Pennsylvania	11,860	2.3	16.2	85.8	12,046	2.3	16.2	94.8
Ohio	10,824	2.6	16.0	93.3	10,794	3.1	16.0	91.0
Indiana	10,876	2.8	11.4	65.8	10,887	3.5	11.4	53.0
Illinois	10,527	2.8	11.1	72.0	10,572	3.2	11.1	85.6
West Virginia	11,610	0.9	15.4	100.8	11,825	2.3	15.4	88.1
Kentucky	10,946	3.6	15.6	76.1	10,964	3.1	15.6	64.4

* 1975 dollars, delivered in 1975.

Table 2-5

Typical "Compliance Option" Coals for SIP Units in the ORBES Counties

Coal Supply Region	Uncleaned or Cleaned	Average Percent Sulfur	Btu/lb	Average Percent Ash
Northern Appalachia	Uncleaned	2.60	12,000	9.87
Northern Appalachia	Cleaned	2.10	13,200	5.63
Central Appalachia	Uncleaned	1.60	12,000	8.00
Central Appalachia	Cleaned	1.20	13,200	4.40
Interior Eastern	Uncleaned	3.60	11,000	10.30
Interior Eastern	Cleaned	2.60	12,100	5.98

Scenario 4 — Low Growth in Electricity Demand

Demand. The "target" figures for this scenario are considered to represent a low average rate of growth in electricity demand: 1.6 percent per year between 1976 and 1985, and 1.6 percent per year between 1985 and 2000. These rates equate to an average growth of 1.6 percent per year over the simulation period, as specified by the Core Team.

Siting. The siting patterns are similar to those of Scenario 2; but, because of the very low growth in demand, fewer units are sited (see Figure 2-4).

Retirements. Same as Scenario 2.

Emission Regulations. Same as Scenario 2.

Compliance. Same as Scenario 2 (SIP compliance by 1984).

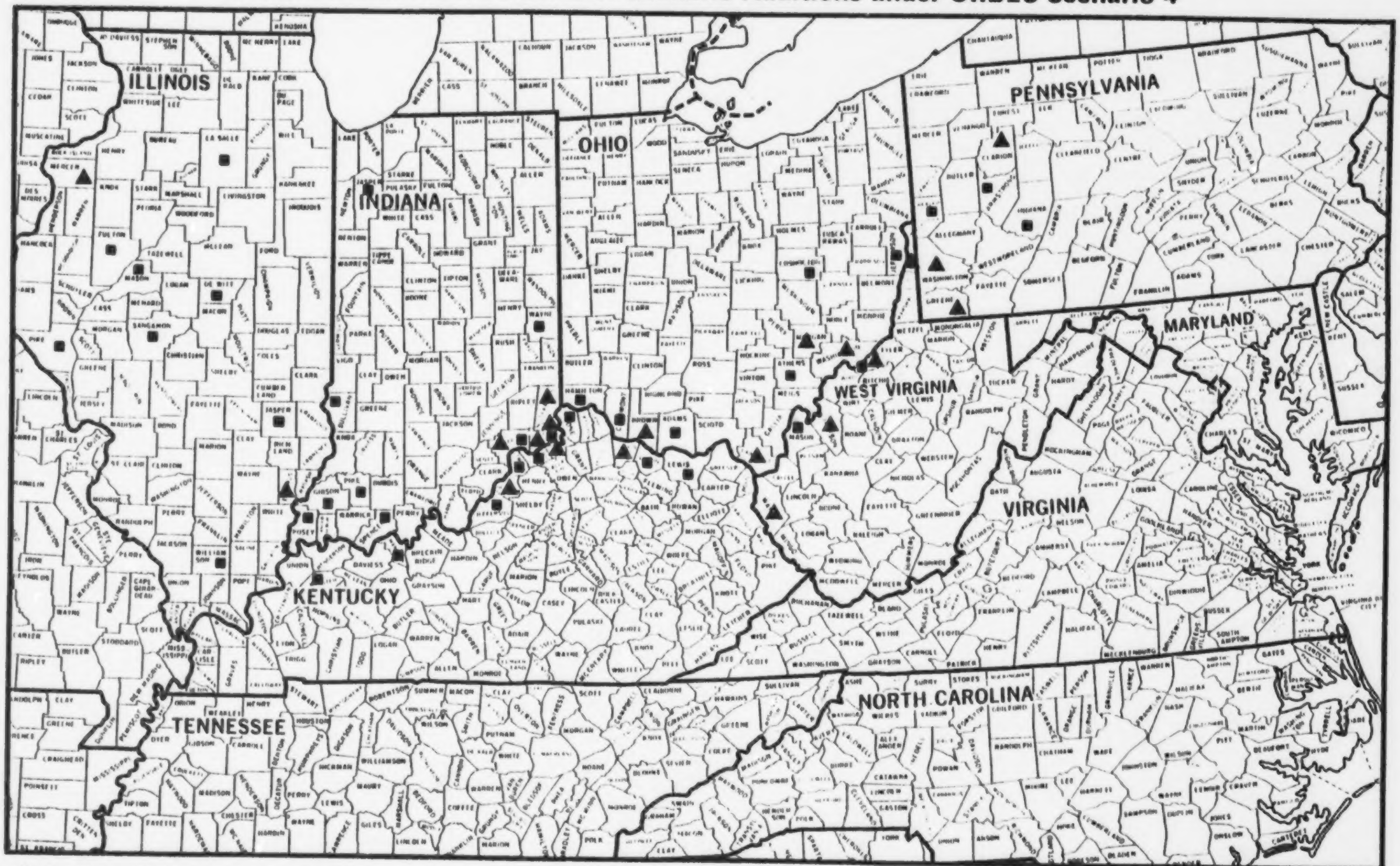
Dispatch. Economic dispatch, as in the preceding scenarios.

Scenario 7 — High Growth in Electricity Demand, Least-Cost Dispatching, and a 45-Year Unit Lifetime

Demand. Rates of growth in the area's electricity generation, selected to approximate the April 1979 utility submissions to the National Electric Reliability Councils, average 3.9 percent per year from 1976 to 1985 and 3.9 percent per year from 1985 to 2000.

Siting. Similar to Scenario 2, with the following exceptions: to satisfy the higher growth rate criterion, an additional 33 GW of RNSPS coal-fired capacity is sited. Furthermore, because of the assumption of an extended (45-year) lifetime, an additional 16.4 GW of unretired SIP capacity remains available to meet the higher load requirements.

Figure 2-4
Counties with Planned Units or Scenario Additions under ORBES Scenario 4


ILLINOIS
INDIANA
OHIO
PENNSYLVANIA
MARYLAND
WEST VIRGINIA
VIRGINIA
KENTUCKY
TENNESSEE
NORTH CAROLINA

Note: Scenario 4 assumes conventional technology and base-case environmental controls.

■ Planned units
▲ Scenario additions

Retirements. In Scenario 7 (and 7a), the coal-unit lifetime is extended to 45 years.

Emission Regulations. Same as Scenario 2, the base case.

Compliance. Same as Scenario 2 (SIP compliance by 1984).

Dispatch. Economic dispatch, as in preceding scenarios.

Scenario 7a — High Growth in Electricity Demand, Least-Emissions Dispatching, and a 45-Year Unit Lifetime

Demand. Same as Scenario 7.

Siting. Same as Scenario 7.

Retirements. Same as Scenario 7 (45-year lifetime for coal units).

Emission Regulations. Same as Scenario 2.

Compliance. Same as Scenario 2.

Dispatch. In Scenario 7a, the dispatch algorithm is modified so that dispatching no longer occurs under the criterion of least cost. Rather, a new criterion is tested: least emissions for coal-fired units; least cost for other units.

For this scenario the USM dispatches coal units in order of least emissions by regulatory class. SIP units are classified as either urban or rural units. NSPS units are generally those that come on line during the period from 1977 through 1982; RNSPS units are generally those that come on line in 1983 and later. In states where the SIP limitation (whether for urban or rural units) is stricter than the federal NSPS, the unit must meet the SIP. Thus, "least emissions" are determined by the stringency of the applicable SO_2 emission limit. One resultant dispatch order is shown in Table 2-6.

Table 2-6

Least-Emissions Dispatch Order for a Particular Set of Coal-Fired Units

Dispatch Order	Class of Coal-Fired Units
1st	RNSPS units
2d	NSPS units
3d	Urban SIP units
4th	Rural SIP units

In practice it may not always be possible to baseload the newer, cleaner RNSPS units, but the results of this scenario will suggest whether least-emissions dispatching might provide significant emission reductions.

Scenario 7b — High Growth in Electricity Demand, Least-Cost Dispatching, and a 35-Year Unit Lifetime

Demand. Same as Scenario 7.

Siting. Same as Scenario 7, except that an additional 13.8 GW of RNSPS units are sited to replace the SIP retirements.

Retirements. Same as Scenario 2 (35-year lifetime for coal units).

Emission Regulations. Same as Scenario 2.

Compliance. Same as Scenario 2.

Dispatch. Economic dispatching, as in preceding scenarios.

3. RESULTS

3.1 Introduction

This section presents the results of a detailed analysis of the air pollutant emissions and economic and energy impacts due to electric utility operations in the Ohio River Basin from 1976 to 2000. The issues and selected key findings have been summarized in the two preceding sections. In addition, the nomenclature, descriptions, assumptions, and rationale for each scenario have been discussed.

The results presented here concern selected measures of principal interest in the ORBES area. These measures include:

- SO_2 emissions
- NO_x emissions
- Total emitted particulates
- Emissions by type of unit (i.e., SIP-, NSPS-, and RNSPS-regulated units)
- Price of electricity to ultimate consumers and cumulative revenues from these consumers
- Cumulative capital costs of retrofitted and new flue gas desulfurization (FGD) systems
- Cumulative capital costs of retrofitted and new electrostatic precipitators (ESPs)
- Cumulative capital costs of new generating capacity

Emissions are given as yearly totals, usually for 1985 and 2000, or as a trend over the period from 1976 through 2000. All costs are expressed in constant 1975 dollars and may be inflated to current-year dollars by the reader. Prices are given as yearly averages, usually for 1985 or 2000, or as a trend over the 1976-2000 period. Cumulative capital costs and revenues from consumers cover the 1976-2000 period. Since the cumulative capital costs discussed and shown in the tables include only the costs of generating capacity and pollution control equipment installed in the ORBES counties between 1976 and 2000, the capital costs required for units coming on line after 2000 are excluded. However, these costs are included in our calculations of the price of electricity and required revenues, since some expenditures for these units will begin before the year 2000.

By comparing scenarios differing from one another in only one key variable, we performed various sensitivity analyses. The results of these analyses reveal the implications of variations in future policies and circumstances affecting utility operations. It should be understood that these results are not to be interpreted as absolute forecasts of what will occur. They are intended to illustrate the importance of certain key factors and to indicate the significance of various utility decisions or potential regulatory options as these could change the impacts presented in this report. Hence, the comparative differences between scenarios are the subjects of principal concern in this discussion.

We begin this section with a brief discussion of background results. These results concern: (a) generating capacities projected over time in order to meet consumer demand, anticipated utility reserve margins, and availability criteria; (b) electricity generation, by type of unit, resulting from system dispatching to meet projected seasonal load duration curves; and (c) coal consumption.

Next we present the results of the base-case scenario. Each of the other scenarios is then compared with the base case (or, when necessary, with some other "baseline" scenario, as in the comparison between Scenarios 7 and 7a). Finally, we discuss a forecast of electricity demand, which is responsive to changes in projected electricity prices and consumer income levels.

It is assumed that the reader has reviewed Sections 1 and 2 and is therefore familiar with the nature of each scenario. Accordingly, our references to scenarios here will generally be only by scenario number.

3.2 Background Results

Future electrical generating capacity in the ORBES area is projected to depend heavily upon coal-fired generation, as is the case today. Table 3-1 shows the projected net generating capability in gigawatts (GW), for power plants located in the ORBES counties, under the base case (Scenario 2). Tables 3-2 and 3-3 show comparable projections for Scenarios 4 and 7b, respectively.

Under Scenario 2, only nuclear capacity increases its percentage share of total capacity by the year 2000. While nuclear capacity increases by 428 percent, coal capacity increases by 88 percent and oil by 21 percent. As for "other" capacity, hydro and pumped storage increase by 220 percent; and combustion turbines, by 74 percent. Total ORBES capacity increases by 95 percent by 2000. It should be noted that, in this study, no nuclear plants were assumed to be added in the ORBES area beyond those already announced by the electric utilities. (If actual nuclear capacity additions prove to be lower than those assumed here, future emissions will be higher for the same level of electricity generation.)

Table 3-4 shows projected generation by fuel type. The figures for total generation in the ORBES counties were specified by the Core Team, and appropriate demand growth rates were applied to the load curves in the USM to approximate these figures. (See Appendix A for a discussion of model validation and calibration.)

Under Scenario 2, utility coal consumption in the ORBES counties increases from 166 million tons in 1976 to 202 million tons in 1985, reaching about 289 million tons in the year 2000 (see Table 3-5 and Figure 3-1). One major assumption made by the Core Team was that only those coals mined in proximity to the ORBES area would be consumed in the ORBES counties. Appendix B contains more information on these potential coal supplies and coal-supply options.

Table 3-1

Projected Net Generating Capability in the ORBES Counties under Base-Case Scenario 2

	1976		1985		2000	
	GW	(%)	GW	(%)	GW	(%)
Nuclear	2.1	(2.6)	9.6	(8.9)	11.1	(7.1)
Coal	72.7	(89.6)	90.6	(83.7)	137.0	(87.2)
Oil	2.4	(3.0)	3.4	(3.1)	2.0	(1.3)
Other	3.9	(4.8)	4.6	(4.3)	7.1	(4.5)
TOTAL	81.1	(100.0)	108.2	(100.0)	157.2	(100.0)

Table 3-2

Projected Net Generating Capability in the ORBES Counties under Low-Growth Scenario 4

	1985		2000	
	GW	(%)	GW	(%)
Nuclear	7.4	(7.5)	11.1	(9.2)
Coal	83.9	(84.7)	101.8	(84.3)
Oil	3.4	(3.4)	2.0	(1.7)
Other	4.4	(4.4)	5.9	(4.8)
TOTAL	99.0	(100.0)	120.8	(100.0)

Table 3-3

Projected Net Generating Capability in the ORBES Counties under High-Growth Scenario 7b

	1985		2000	
	GW	(%)	GW	(%)
Nuclear	9.5	(8.8)	11.1	(5.4)
Coal	90.0	(83.7)	184.7	(89.0)
Oil	3.4	(3.2)	2.0	(1.0)
Other	4.6	(4.3)	9.6	(4.6)
TOTAL	107.5	(100.0)	207.4	(100.0)

Table 3-4

Projected Generation by Fuel Type in the ORBES Counties*

	1976		1985		2000	
	Base-Case Scenario 2 TWh (%)					
Nuclear	10.0	(2.6)	54.4	(10.1)	62.9	(8.5)
Coal	363.1	(95.6)	477.0	(88.2)	670.5	(90.5)
Oil	2.4	(0.6)	4.3	(0.8)	2.3	(0.3)
Other	4.4	(1.2)	4.9	(0.9)	5.1	(0.7)
TOTAL	379.9	(100.0)	540.6	(100.0)	740.8	(100.0)
	Low-Growth Scenario 4 TWh (%)					
Nuclear	–	–	42.3	(9.6)	62.9	(11.3)
Coal	–	–	391.3	(89.0)	486.5	(87.5)
Oil	–	–	1.6	(0.4)	1.6	(0.3)
Other	–	–	4.5	(1.0)	5.0	(0.9)
TOTAL	–	–	439.7	(100.0)	556.0	(100.0)
	High-Growth Scenario 7b TWh (%)					
Nuclear	–	–	54.3	(10.3)	62.9	(6.9)
Coal	–	–	464.2	(88.0)	837.3	(92.4)
Oil	–	–	4.3	(0.5)	2.5	(0.1)
Other	–	–	4.7	(0.9)	5.3	(0.6)
TOTAL	–	–	527.5	(100.0)	907.6	(100.0)

* Total generation specified by the Core Team.

Table 3-5

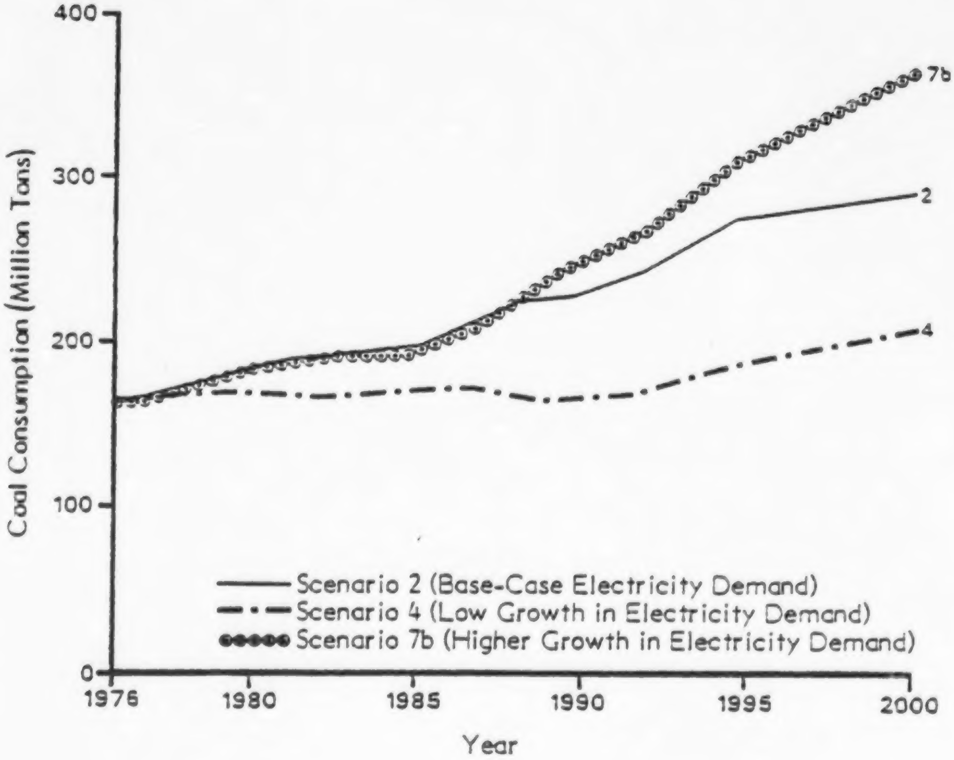
Coals Consumed in the ORBES Counties in the Year 2000 under Scenario 2

		Percentage of Supply for Counties in Each State							
	Total (10^6 Tons)	Northern Appalachian Coal (UC)	Central Appalachian Coal (UC)	Southern Appalachian Coal (UC)	Interior Eastern Coal (UC)	Northern Appalachian Coal (C)	Central Appalachian Coal (C)	Interior Eastern Coal (C)	
Pennsylvania	42.6	69.0	21.0			10.0			
Ohio	54.2	97.0					3.0		
Indiana	51.8		9.0		87.0		4.0		
Illinois	41.8			4.0	88.0			8.0	
West Virginia	42.7		100.0						
Kentucky	56.2	78.0		22.0			*		
Total ORBES Counties	289.3	82.2	99.7	1.6	94.3	4.2	4.0	3.3	10^6 tons
	100.0	28.5	34.0	0.5	33.0	1.5	1.5	1.0	Percent

* Less than 1 percent.

Figure 3-1

Annual Electric Utility Coal Consumption
in the ORBES Counties



3.3 Base-Case Results
(Scenario 2)

The Dominant Contribution to ORBES County SO_2 Emissions by SIP Units

One key finding in this study is that, until after the year 2000, SO_2 emissions in the ORBES counties will come predominantly from units whose emission limits are governed by the State Implementation Plans. These are generating units on line largely before 1976. This finding is illustrated in Figure 3-2, which shows annual net generation and SO_2 emissions by generating-unit type. In the graph of net generation, "RNSPS" refers to generation from coal-steam units governed by the 1979 revised New Source Performance Standards; "SIP" refers to generation from coal units governed by State Implementation Plans; "Nuclear" refers to generation from nuclear units; "NSPS," to generation by coal units subject to the 1971 New Source Performance Standards; and "Other," to generation from all other units. The RNSPS, SIP, and NSPS designations refer only to coal generating units. In the graph of SO_2 emissions, the same designations appear for the coal units. Since SO_2 emissions from oil units in the ORBES counties are relatively insignificant (less than 1 percent), these data are not shown.

Two major trends are evident with regard to total ORBES SO_2 emissions. Total emissions follow a pattern similar to emissions from the SIP units. The first major trend – the decline in SO_2 emissions from the SIP units between 1977 and 1985 – is due to the effects of SIP compliance. Thus, if SIP units comply with anticipated State Implementation Plan SO_2 limits, their regional emissions will decrease from 8.94 million tons in 1976 to 5.6 million tons in 1985 (a decrease of 37 percent). The second distinct trend – in which SIP-unit emissions after 1985 continue to decline, dropping to about 2.93 million tons in the year 2000 (a 67 percent decrease from 1976) – is due to the scenario assumption that coal units will retire after 35 years of operation. The effect of this assumption is also represented in the net-generation graph of Figure 3-2, which shows SIP-unit generation decreasing during the 1985-2000 period from about 370 to 176 terawatt-hours.

Figure 3-2

Annual Electric Utility Net Generation and Coal-Plant SO_2 Emissions in the ORBES Counties under Scenario 2 (Base Case with SIP Compliance)

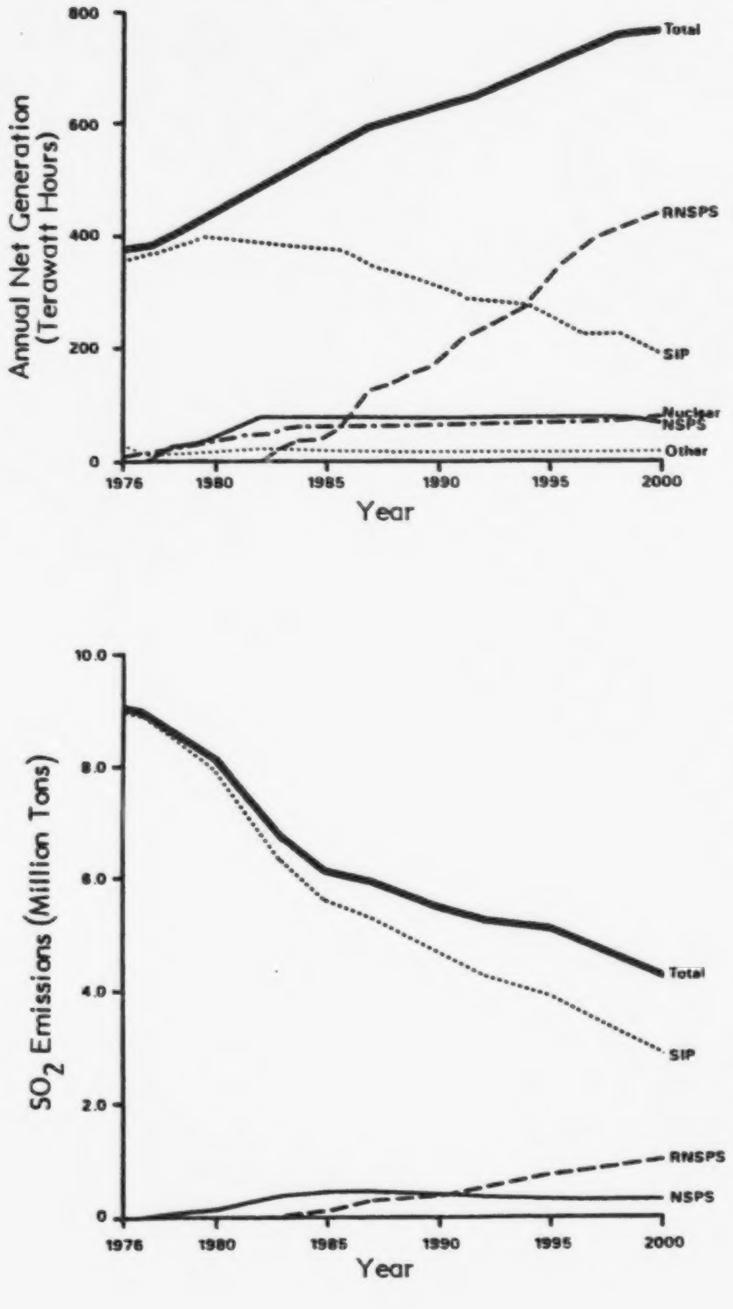


Figure 3-3 illustrates the cumulative projected retirements of coal-fired units in the ORBES counties. Under a 35-year unit lifetime, units built in the early 1960s will not be retired until the late 1990s, and those in service after 1965 will remain in service beyond 2000. Replacing this capacity will increase utility costs, and it is entirely plausible that utilities will prefer to extend the lives of these units to 45 years or more.*

In summary, the base-case results presented thus far show that SO_2 emissions in the ORBES counties decrease by the year 2000, and that this decrease is primarily a function of SIP-unit compliance between 1977 and 1984 and of the 35-year retirement age for SIP units that takes effect after 1985. After the year 2000, emission levels in the ORBES area will also depend significantly on SIP-unit retirement schedules.

NO_x Emissions and Total Emitted Particulates

Although total generation by coal units increases by 85 percent between 1976 and 2000, NO_x emissions under Scenario 2 increase by 34 percent, from 1.49 million tons in 1976 to 2.0 million tons in 2000 (see Figure 3-4).

Under Scenario 2, total emitted particulates from coal units in the ORBES counties decrease from about 1.38 million tons in 1976 to 0.19 million tons by the year 2000. Figure 3-5 reveals two trends. The first, the substantial decline in particulate emissions from 1976 to 1985, is due to SIP-unit compliance with SIP particulate standards. The second, the relatively flat level of particulate emissions from 1985 to 2000, is due to SIP retirements and to the replacement of SIP capacity by RNSPS units, which are more strictly controlled. Given the relatively flat level of particulate emissions after 1985, concern may shift from particulate levels in general to the emission of fine particles of less than 2 microns in size, since these are thought to be more harmful than larger-sized particles.

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* The effects of alternative assumptions regarding generating-unit lifetimes are discussed in Sections 3.4 and 3.8.

Figure 3-3

Cumulative Coal-Plant Retirements in the ORBES Counties Assuming a 35-Year Unit Life (Scenario 2)

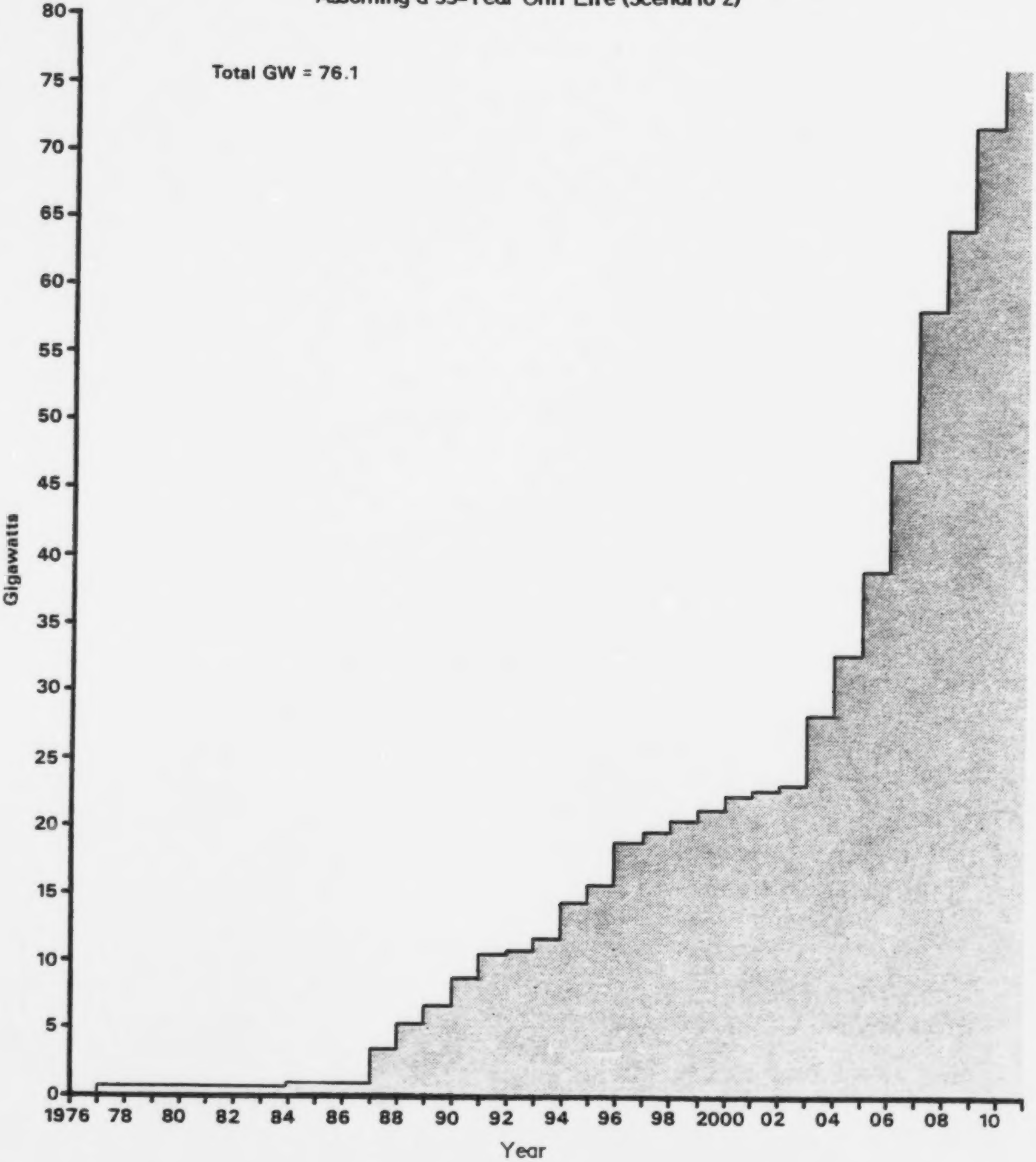


Figure 3-4

Annual Electric Utility Coal-Plant NO_x Emissions in the ORBES Counties under Base-Case Scenario 2

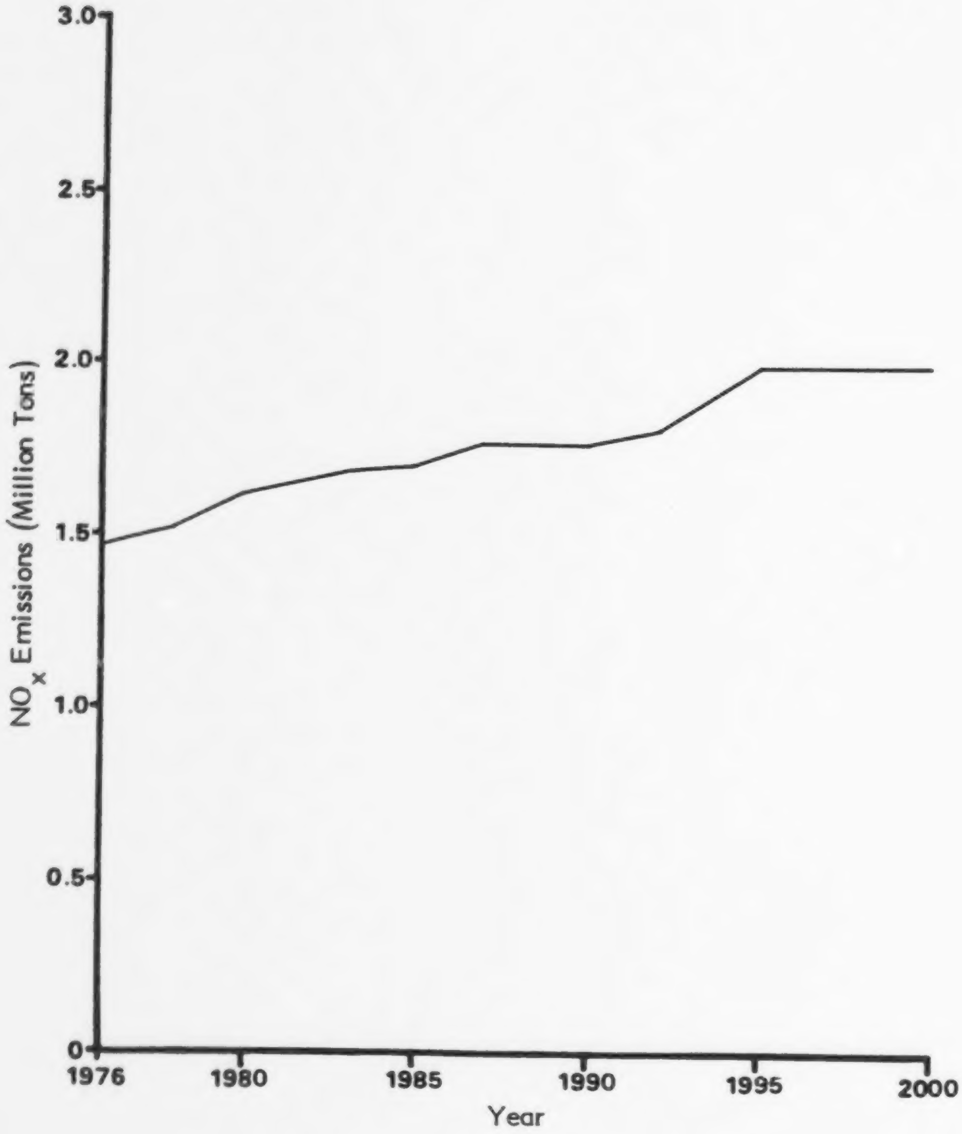
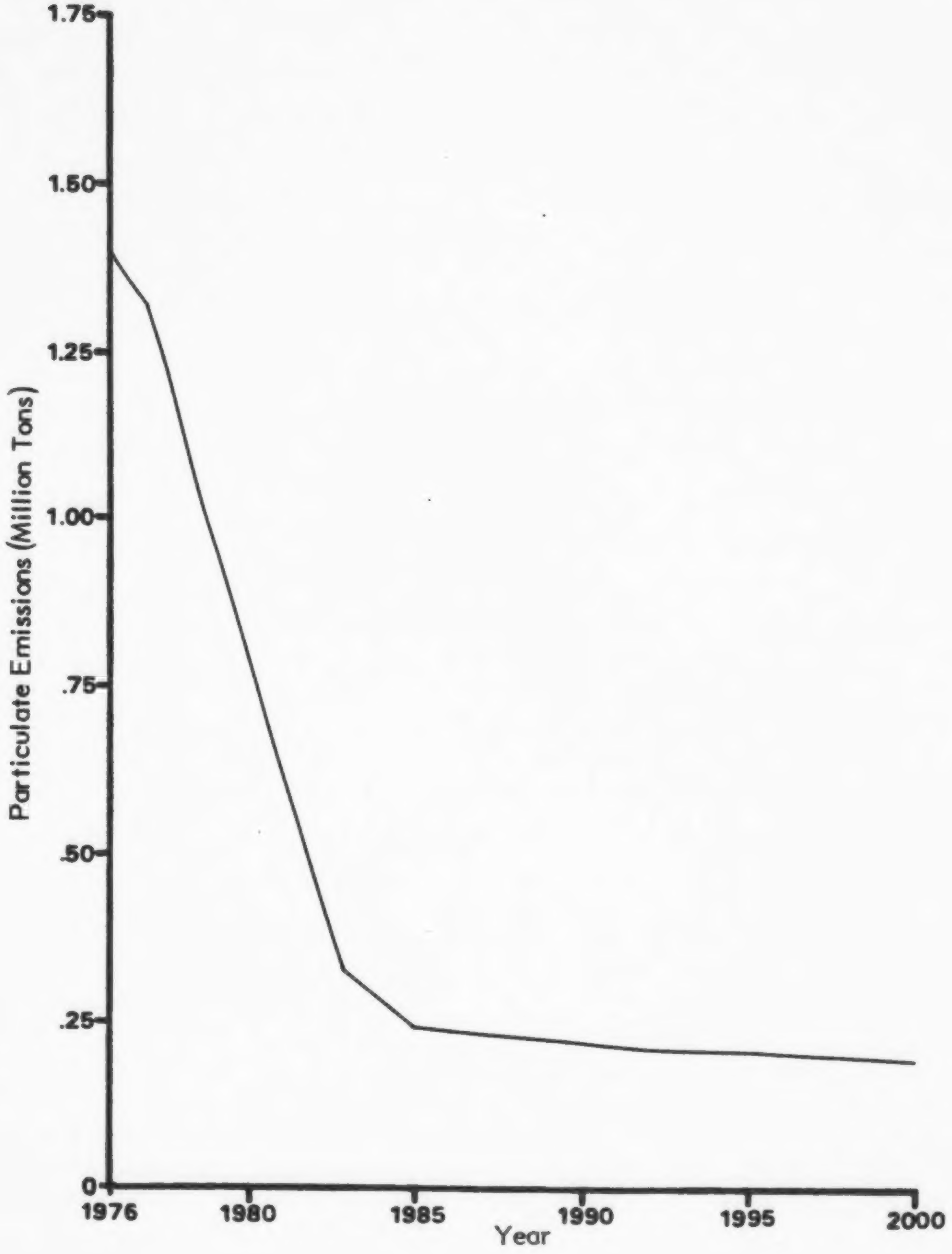


Figure 3-5

Annual Electric Utility Coal-Plant Particulate Emissions in the ORBES Counties under Base-Case Scenario 2



Electricity Prices

Under Scenario 2, the real price of electricity to ultimate consumers increases by roughly 2.5 percent per year, measured in constant 1975 dollars. Three trends occur, as shown in Figure 3-6.

First, the real price of electricity in constant 1975 dollars rises from 2.58¢/kWh in 1976 to 3.87¢/kWh in 1985, an increase of 4.6 percent per year. This reflects the added costs of complying with base-case emission limits through 1985, meeting rising fuel and capital costs, and satisfying increased electricity demand (growing at about 4 percent per year during this period). The second slope, from 1985 to about 1995, shows a relatively flat price of electricity. This is due partly to the fact that the compounded annual growth rate specified by the Core Team for the 1985-2000 period is lower than that for the preceding years. Thus, since costs increase more slowly after 1985 than they did betweeen 1976 and 1984, when pollution controls were retrofitted, prices do not increase as rapidly.

Third, from about 1995 to the year 2000, the price of electricity increases by about 2.1 percent per year. This is due to the building of new capacity both to satisfy base-case demand growth and to replace retired plants. The number of retirements due to the assumption of a 35-year unit lifetime increases significantly after 1995, as shown in Figure 3-3.

In order to reflect the cumulative costs to ultimate consumers of the electricity generated in the ORBES counties, we have also calculated the cumulative revenues required from consumers over the 1976-2000 period; for Scenario 2, the cumulative revenues required from ultimate consumers amount to $525 billion over the 1976-2000 period.*

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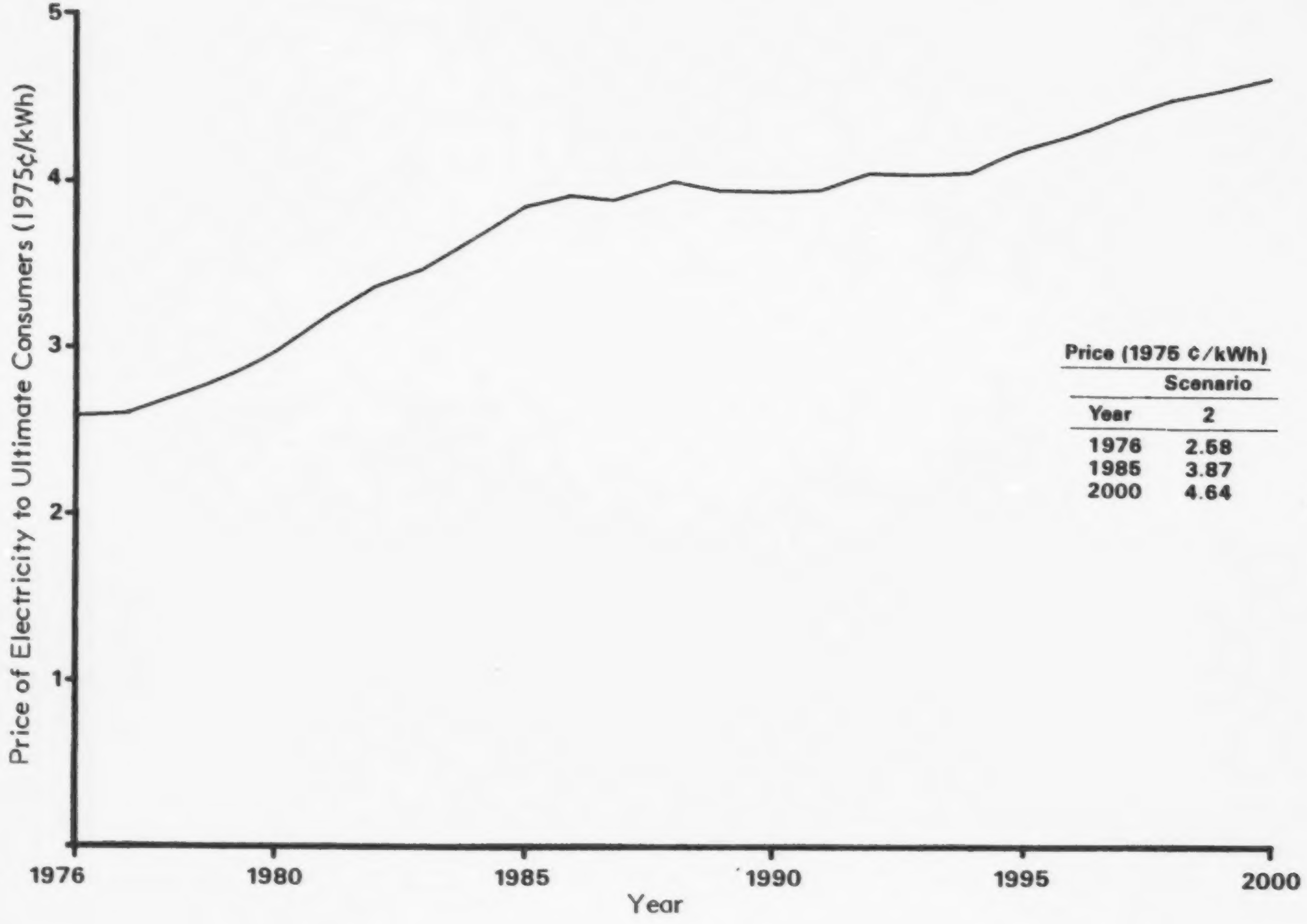
* The price of electricity in a given year represents the costs incurred by a utility plus a rate of return. In order to compare expenditures that are spread over a numbers of years, cumulative revenues required from ultimate consumers provide a somewhat different representation of the differences between alternative price projections. Comparisons between scenarios using electricity prices at only one or two points in time do not fully capture the differences in capital costs and operating expenditures required over the entire study period. In order to compare the average price changes over the period of this study, 1976-2000, cumulative revenues from alternative scenarios have been provided. Differences in cumulative revenues represent average price differences over the time interval, while differences in anticipated electric prices at a point in time reflect a snapshot of these differences.

Figure 3-6

Electricity Prices in the ORBES Counties
under Base-Case Scenario 2



Price (1975 ¢/kWh)

	Scenario
Year	2
1976	2.58
1985	3.87
2000	4.64

Capital Costs

Cumulative Capital Costs of FGD. As shown in Table 3-6, by the year 2000 under Scenario 2, a total of 117 GW of capacity have flue gas desulfurization systems. These systems together cost about $12.6 billion. Thus, the total cost averages $107 per kilowatt. About 26 GW of SIP-governed capacity are projected to retrofit FGDs to meet the base-case SIP emission limits. These retrofitted FGDs cost about $2.1 billion, at an average cost of about $81 per kilowatt. Compared with the FGDs on NSPS and RNSPS units, those on SIP units meet less stringent emission standards and hence have a lower apparent cost per kilowatt of plant capacity than for RNSPS plants. However, their capital costs are higher for a given emission standard and specified scrubber size, as indicated by comparing the costs of scrubbers on NSPS units. As for the NSPS and RNSPS units, about 91 GW install FGDs to meet the more stringent emission standards; these FGDs are installed at a total cost of $10.4 billion, averaging about $115 per kilowatt. All RNSPS units will use FGD.

Table 3-6

Cumulative Capital Costs for FGDs through 2000 under Base-Case Scenario 2

Type of Unit	GW of Capacity with FGD*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	26.2	2.12	81
NSPS	12.0	0.81	68
RNSPS	78.7	9.62	122
TOTAL	116.9	12.55	107**

* After capacity penalty.

** Not a total; represents average $/kW.

Cumulative Capital Costs of ESPs. By the year 2000 under Scenario 2, about 69.5 GW of SIP-governed capacity require retrofitted ESPs. These ESPs cost \$3.30 billion, or about \$47/kW (see Table 3-7). ESPs costing about \$2.8 billion, or about \$30/kW, are required for the 90.7 GW of NSPS and RNSPS capacity. Although NSPS and RNSPS units are meeting somewhat more stringent particulate standards the cost per kilowatt for retrofitting ESPs is higher than the cost of building a particulate control device on a new unit.

Table 3-7

Cumulative Capital Costs for ESPs through 2000 under Base-Case Scenario 2

Type of Unit	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	69.5	3.30	47
NSPS	12.0	0.34	28
RNSPS	78.7	2.48	32
TOTAL	160.2	6.12	38**

* After capacity penalty.

** Not a total; represents average $/kW.

Cumulative Capital Costs of New Generating Capacity. Under the base-case assumptions, 95.5 GW* of coal capacity come on line between 1976 and 2000, at a cumulative capital cost of of \$67.0 billion (see Table 3-8). During the same period, nearly 10 GW of nuclear capacity are built at a cost of \$8.3 billion.

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* Before capacity penalties.

Table 3-8

Cumulative Capital Cost of New Installed Generating Capacity Built through 2000 under Base-Case Scenario 2

Type of Generating Unit	GW of New Installed Capacity*	Cumulative Capital Costs (Billions of 1975$)	$/kW
Coal	95.5	67.0	702
Nuclear	9.8	8.3	846
	105.3	75.3	715**

* Before capacity penalties.

** Not a total; represents average $/kW.

Summary of Base-Case Results

In summarizing the impacts of the base case, we compare the benefits of current pollution control policies (expressed in reductions in emissions of various pollutants) with the price of electricity and the cost of attaining these reductions.

Thus, for example, the capital costs of meeting base-case demand growth and the specified emission limits will total about $75 billion for the construction of new coal and nuclear capacity coming on line between 1976 and 2000, about $12.6 billion for new and retrofitted FGDs, and about $6.1 billion for new and retrofitted ESPs. The price of electricity, in turn, will increase from 2.58¢/kWh in 1976 to 4.64¢/kWh by the year 2000 (a real-price increase of 80 percent, caused by fuel and capital cost escalation, capacity additions, increased operating costs to meet increased demand, and pollution control costs).

The benefits derived from these capital expenditures and overall costs to consumers can be measured in terms of emission reductions and increased electricity generation. Thus, the expenditures for FGDs (for both retrofitted and new plants) and for cleaned or lower-sulfur coals will reduce annual SO_2 emissions from 8.94 million tons in 1976 to 4.35 million tons in the year 2000 (a 51 percent decrease) if the base-case policies are followed. Furthermore, total emitted particulates will drop from about 1.4 million tons in 1976 to 0.2 million tons in 2000 (an 86 percent decrease). At the same time, the amount of electricity generated will grow from 379.9 TWh to 740.5 TWh over the 1976-2000 period (a 95 percent increase).

In order to determine the degree to which these costs and emission reductions are due to SIP compliance, we now compare Scenarios 2 and 2d.

3.4 Costs, Prices, and Emissions Due to Compliance with Base-Case SIPs (A Comparison of Scenarios 2 and 2d)

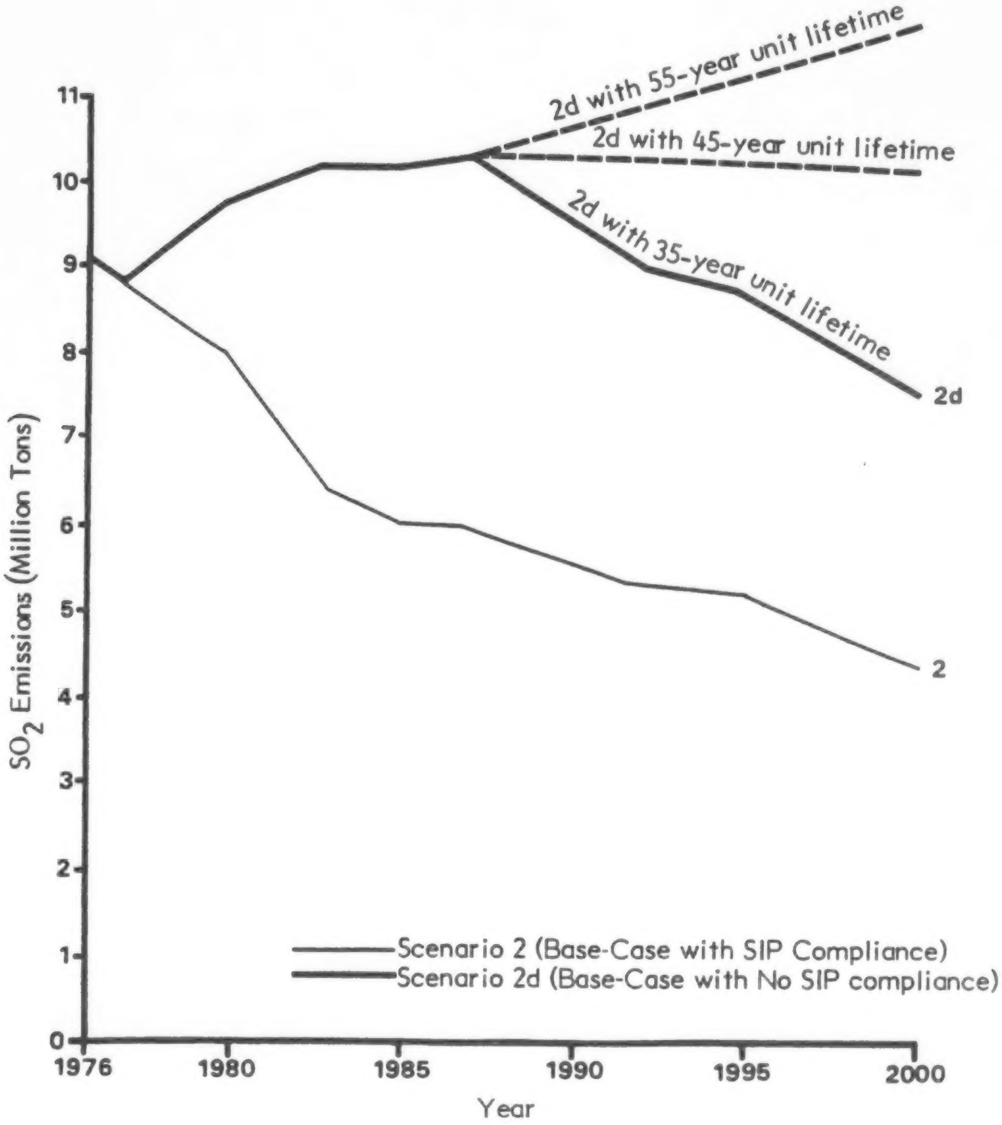
Scenarios 2 and 2d differ with regard to compliance with SIP emission limits for SO_2 and particulates. Thus, as modeled in Scenario 2, all SIP units come into compliance with anticipated average urban and rural SIP emission limits in each state during the period from 1977 through 1984. In Scenario 2d, the SIP units are assumed never to come into compliance. By comparing the results of the two scenarios, we can determine the costs of attaining the expected SIP emission standards and the extent to which emission reductions are due to SIP compliance. Furthermore, with the results of Scenario 2d, we can establish an upper bound (i.e., worst-case estimate assuming base-case demand) for future emissions. As we shall show, post-1985 emissions levels will depend most significantly upon retirement rates for coal-fired SIP plants, assuming SIP compliance occurs.

Emissions

Under Scenario 2d, the base case without SIP compliance, regional SO_2 emissions rise from 8.94 million tons in 1976 to 10.1 million tons in 1985, an increase of about 13 percent (see Figure 3-7). During the same period under Scenario 2d,

Figure 3-7

Annual Electric Utility Coal-Plant SO_2 Emissions



particulate emissions increase about 10 percent, from 1.39 million tons in 1976 to 1.53 million tons in 1985 (see Figure 3-8). It is important to understand that these projections of regional SO_2 and particulate emissions are highly dependent upon the assumptions about coal-unit retirement ages. For example, under these two scenarios we assume a 35-year unit lifetime; and, over the period prior to 2000, this assumption affects only the SIP units. Thus, the decrease in SO_2 emissions in the noncompliance case, from 10.1 million tons in 1985 to 7.6 million tons in 2000 (see Figure 3-7) is due primarily to the assumption of a 35-year unit lifetime. The dashed lines in Figure 3-7 demonstrate this sensitivity by showing projected emissions under Scenario 2d with a 45-year and a 55-year retirement schedule. As can be seen, the longer the SIP-unit retirements are postponed, the higher the level of SO_2 emissions.

Implementation of the expected SIP limits reduces SO_2 and particulate emissions considerably. For example, by 1985, annual SO_2 emissions in the ORBES counties total about 6.1 million tons under Scenario 2 (nearly 40 percent less than under Scenario 2d, and nearly 32 percent less than 1976 SO_2 emissions). Under Scenario 2, particulate emissions in 1985 total 0.25 million tons (about 84 percent less than under Scenario 2d, and 82 percent less than 1976 levels). Utility NO_x emissions are not significantly dependent upon current SIP standards.

Electricity Prices

The differences between the curves in Figure 3-9 illustrate the costs to consumers of the base-case pollution control measures required to meet SIP limits. Thus, by 1985 it will cost consumers an additional 0.77¢/kWh (an increment of 25 percent) to pay for SIP compliance. By the year 2000, the price difference will have narrowed, amounting to about 0.20¢/kWh (an increment of 5 percent) to pay for these control measures. Thus, although SIP pollution control costs will drive up electricity prices in the near term (1976 to 1985), by the year 2000 the compelling forces behind rising prices will be capacity expansion and capacity replacement. It should be pointed out that, for the

Figure 3-8

Annual Electric Utility Coal-Plant Particulate Emissions in the ORBES Counties under Scenarios 2 and 2d

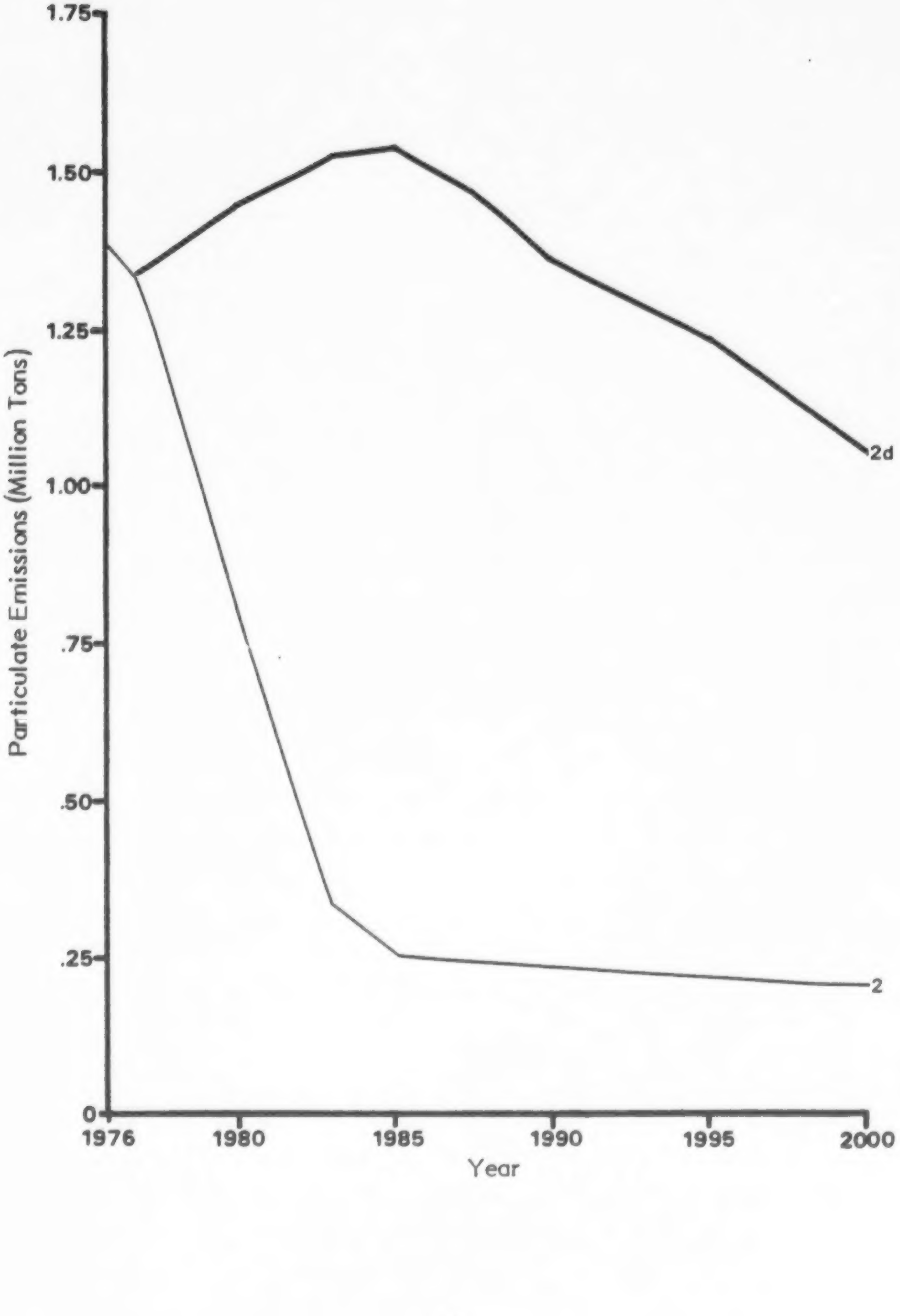
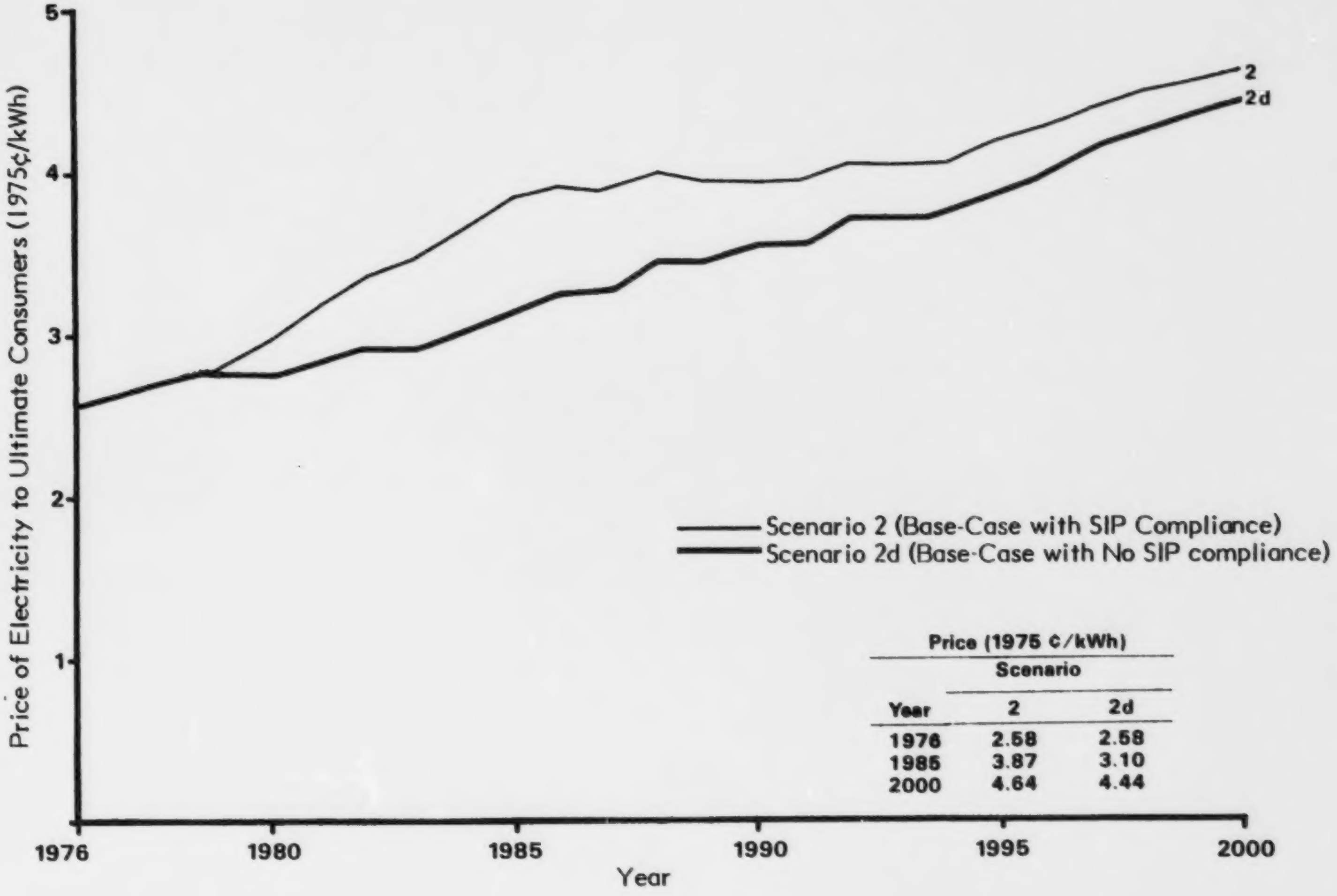


Figure 3-9

Electricity Prices in the ORBES Counties
under Scenarios 2 and 2d



Price (1975 ¢/kWh)

Year	Scenario 2	Scenario 2d
1976	2.58	2.58
1985	3.87	3.10
2000	4.64	4.44

period from 1985 to 1995, the slope for Scenario 2 is relatively flat, whereas the slope for Scenario 2d rises slightly. The flatness of the slope for Scenario 2 (from 1985-1995) stems from depreciating retrofitted emission control devices over a five-year period, which tends to lower utility costs after taxes. Thus, prices to the customer in Scenario 2 do not rise as rapidly in the early 1990s as they did before, although they are already higher than the prices in Scenario 2d. By the year 2000, Scenarios 2 and 2d do not differ significantly in terms of the price of electricity (4.64¢/kWh for Scenario 2, and 4.44¢/kWh for Scenario 2d).

Cumulative revenues required from ultimate consumers between 1976 and 2000 are projected to be $525 billion under Scenario 2 and $475 billion under Scenario 2d. This represents a 10 percent increase in consumer costs over the period before 2000 to achieve compliance with expected SIPs.

Capital Costs

Table 3-9 shows the cumulative capital costs of FGDs through 2000. Under Scenario 2, these costs total $12.6 billion; and under Scenario 2d, $10.3 billion. The difference is due to the SIP units' retrofitting of FGDs. Thus, the capital cost of attaining anticipated average SIP SO_2 limits by 1985 will amount to about $2.2 billion.

The cumulative capital costs of ESPs through 2000 total about $6.1 billion under Scenario 2 and about $2.8 billion under Scenario 2d, a difference of $3.3 billion (Table 3-10). This difference is attributed entirely to the SIP particulate limits, although it is likely that ESPs would be installed on a number of existing units even in the absence of SIPs.

The capital costs of new generating capacity through 2000 are about the same under Scenario 2d as in the base case, with slightly higher costs occurring under Scenario 2 because of capacity penalties imposed by retrofitted pollution controls.

Table 3-9

Cumulative Cost of FGDs through 2000 under Scenarios 2 and 2d

	Scenario 2			Scenario 2d		
Type of Unit	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	26.2	2.12	81	0	0	0
NSPS	12.0	0.81	68	12.0	0.81	68
RNSPS	77.9	9.52	122	77.9	9.52	122
TOTAL	116.93	12.55	107**	89.9	10.33	115**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-10

Cumulative Capital Costs of ESPs through 2000 under Scenarios 2 and 2d

Type of Unit	Scenario 2			Scenario 2d		
	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	69.5	3.30	47	0	0	0
NSPS	12.0	0.34	28	12.0	0.34	28
RNSPS	78.7	2.48	32	77.9	2.45	32
TOTAL	160.2	6.12	38**	89.9	2.79	31**

* After capacity penalty.

** Not a total; represents average $/kW.

Summary Comparison of Scenarios 2 and 2d

In summary, we compare the two scenarios' differences in emission levels with their differences in capital costs, electricity prices, and cumulative revenues over the 1976-2000 period.

From Table 3-11 we see that SIP noncompliance (Scenario 2d) compared with SIP compliance (Scenario 2) reduces FGD costs by 18 percent, ESP costs by 54 percent, and cumulative revenues from consumers by 9 percent. The price of electricity under noncompliance is 20 percent less in 1985 but only 4 percent less in 2000. However, by the year 2000 SO_2 emissions increase by 74 percent, and particulate emissions by 458 percent.

Making the comparison the other way we see that by 1985, compliance with current SIP limits (Scenario 2) will reduce annual SO_2 emissions by about 42 percent, and annual particulate emissions by about 82 percent, compared with emissions generated under noncompliance (Scenario 2d). In 1985, SIP compliance could push up electricity prices by about 0.77¢/kWh (25 percent). Cumulative revenues between 1976 and 2000 will have to increase by about 10 percent (from $475 to $525 billion) to achieve this 42 percent SO_2 reduction and 82 percent particulate reduction occurring in the year 2000.

From Table 3-11 we see also that the 42 percent SO_2 reduction — a reduction of nearly 3.2 million tons per year — will require a 21 percent increase ($2.2 billion) in capital costs for FGDs. As for particulates, the dramatic 82 percent reduction — the difference between 0.19 million tons under Scenario 2 and 1.06 million tons under Scenario 2d — will require a 119 percent increase ($3.3 billion) in capital costs for ESPs. It should be noted, of course, that the capital costs do not reflect the operating costs of these devices. The operating costs are included in the calculation of the price of electricity, which reflects all the costs borne by the utilities each year.

Table 3-11

Percentage Changes in Costs and Emissions under SIP Compliance versus No SIP Compliance (Scenario 2d versus Scenario 2)

	Percentage Change (Scenario 2d/2)
Cumulative capital costs for FGDs (1976-2000)	-18
Cumulative capital costs for ESPs (1976-2000)	-54
Cumulative revenues from ultimate consumers (1976-2000)	-9
Price of electricity	
(1985)	-20
(2000)	-4
SO_2 emissions (2000)	+74
Particulate emissions (2000)	+458

3.5 Costs, Prices, and Emissions Due to Stricter SIPs (A Comparison of Scenarios 2 and 1)

Under Scenario 1, all SIP units must meet SO_2 limits applicable to urban areas in each ORBES state. Thus, by comparing the costs, prices, and emissions of Scenarios 1 and 2, we can determine the impacts of stricter SIP emission limits for SO_2. Over the ORBES counties, the SIP SO_2 limits in Scenario 1 average about 1.3 lb/10^6 Btu; those in Scenario 2 average about 3.3 lb/10^6 Btu. SIP particulate limits in Scenario 1 are the same as those in Scenario 2; thus, differences between the two scenarios are attributable only to stricter SO_2 SIP limits.

Emissions

Under compliance with stricter SIP limits (Scenario 1), regional SO_2 emissions decrease in 1985 to 2.99 million tons per year. This decrease, illustrated in Figure 3-10, represents an incremental reduction from Scenario 2 of 51 percent. By the year 2000, SO_2 emissions under Scenario 1 decrease further, to 2.55 million tons – which, compared with the 4.35 million tons under Scenario 2, represents an incremental reduction of 41 percent. Emissions of NO_x and particulates do not change substantially under these stricter SIPs for SO_2.

Prices

In 1985 the price of electricity reaches 3.87¢/kWh under Scenario 2 and 4.21¢/kWh under Scenario 1. Thus, in 1985 it will cost the consumer 0.34¢/kWh (or 9 percent) more per kilowatt-hour to attain the stricter SO_2 limits compared with the current limits. In the year 2000, with the price of electricity at 4.64¢/kWh under Scenario 2 and at 4.71¢/kWh under Scenario 1, attainment of the stricter limits compared with the base case will cost the consumer 0.07¢/kWh (or 1.5 percent) more. These results are illustrated in Figure 3-11. Cumulative revenue requirements will increase over the period from \$525 to \$544 billion.

Figure 3-10

Annual Electric Utility Coal-Plant SO_2 Emissions in the ORBES Counties under Scenarios 2 and 1

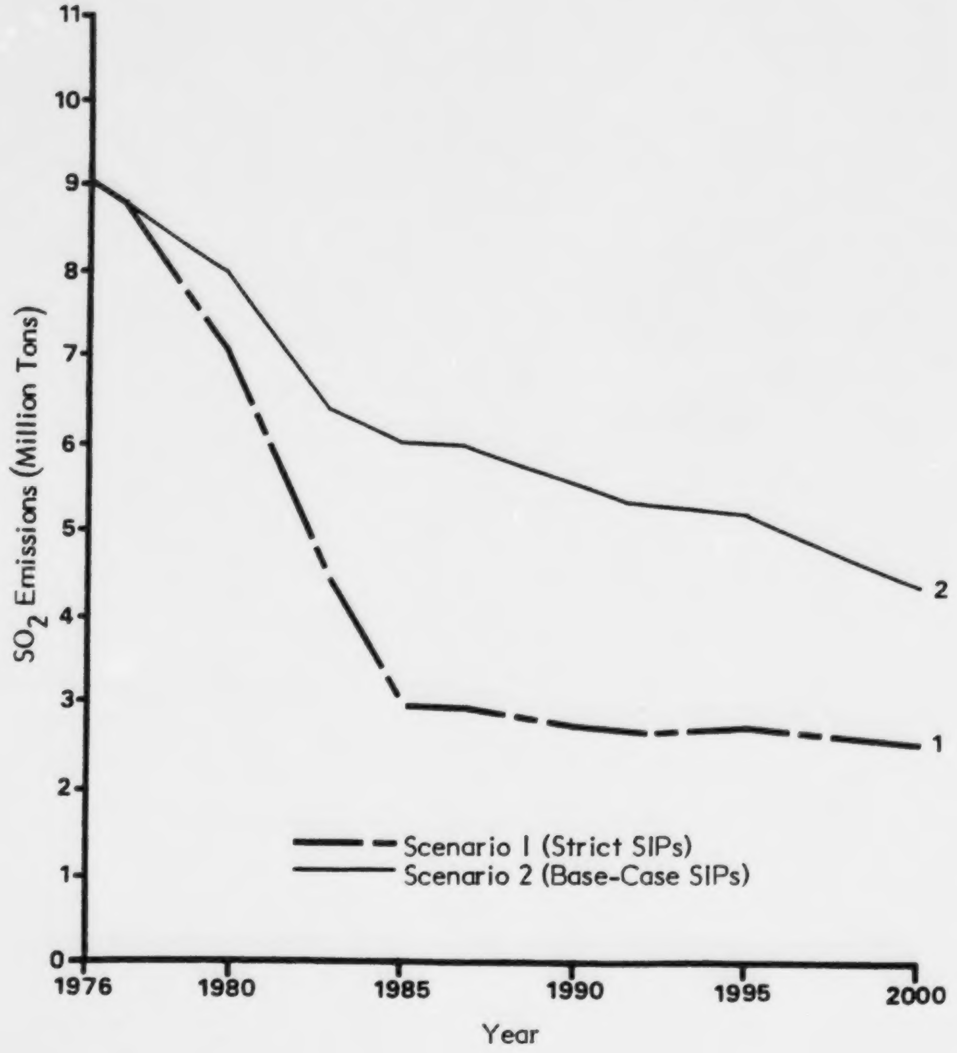
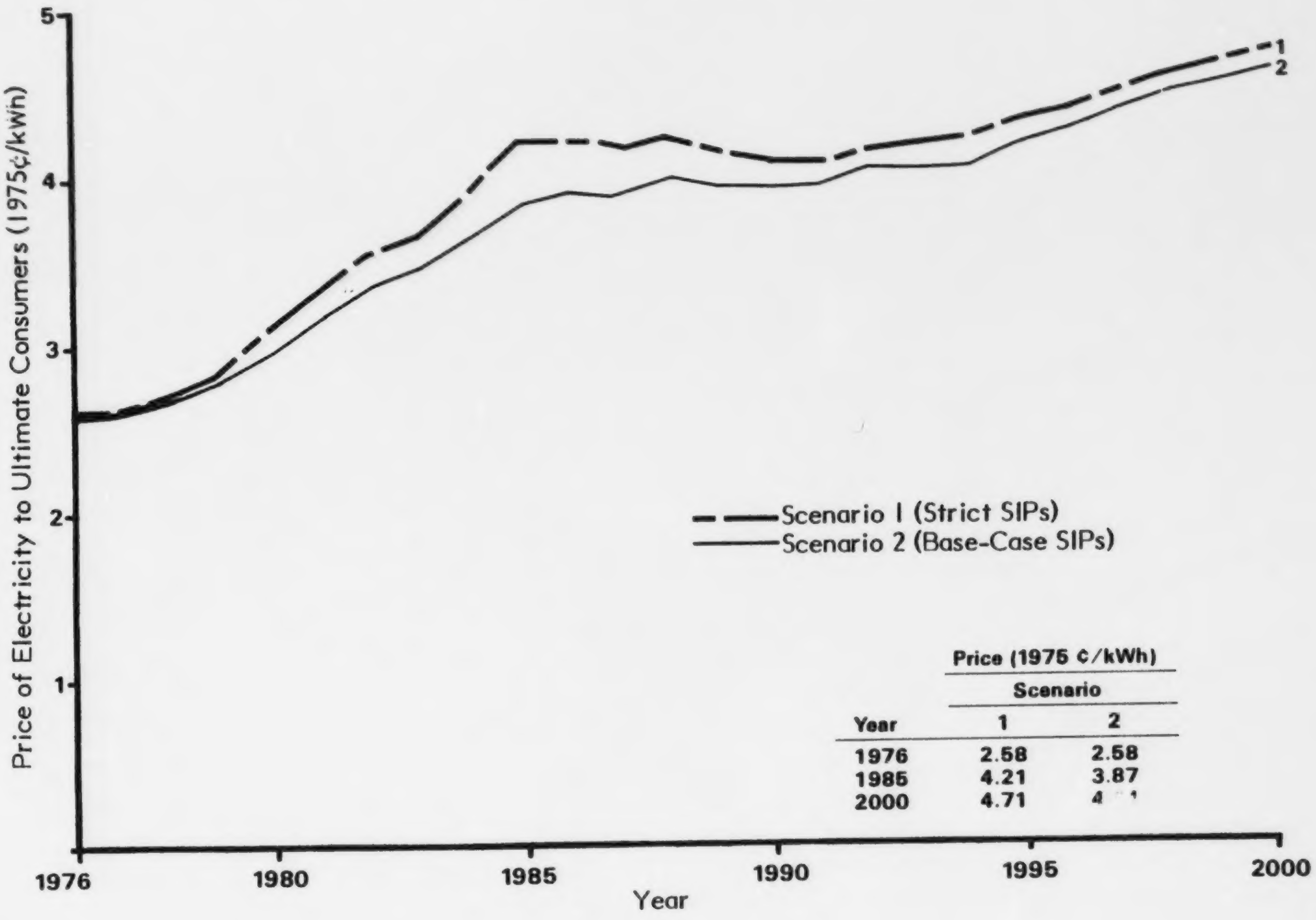


Figure 3-11

Electricity Prices in the ORBES Counties
under Scenarios 2 and 1



	Price (1975 ¢/kWh)	
	Scenario	
Year	1	2
1976	2.58	2.58
1985	4.21	3.87
2000	4.71	4.[illegible]1

Capital Costs

Table 3-12 shows the cumulative capital costs of FGDs through 2000 for Scenarios 1 and 2. The SIP capacity retrofitted with FGDs amounts to nearly 60 GW in Scenario 1 but to only 26 GW in Scenario 2. Under Scenario 1, it costs $6.0 billion to retrofit these SIP units, assuming that retrofitting is feasible on an engineering basis. Thus, the stricter SIP limits cost nearly $4 billion more than the base-case SIP limits. The cost per kilowatt to retrofit SIP units with FGDs averages about $101/kW under Scenario 1 compared with $81/kW under Scenario 2. The costs per kilowatt are also higher than for units meeting the 1971 NSPS.

The cumulative capital costs of ESPs and of new generating capacity under Scenario 1 do not differ significantly from those under Scenario 2.

Summary Comparison of Scenarios 2 and 1

The incremental capital cost of stricter SIPs over the base-case SIPs (Scenario 1 versus Scenario 2) amounts to about $4.0 billion. Assuming that the extensive FGD retrofitting required is in fact achievable, annual SO_2 emissions under the stricter SIPs decrease by 3.1 million tons (51 percent). In 1985, the incremental cost of this reduction to consumers amounts to 0.34¢/kWh, an increase of 9 percent over the base-case price (see Table 3-13). Over the 1976-2000 period, the price increases incurred under the stricter SIPs, reflecting additional capital and operating costs, represent an increase in cumulative revenues of 4 percent above the base case.

3.6 Sensitivity of Costs, Prices, and Emissions to Higher Rates of Growth in Electricity Demand (A Comparison of Scenarios 2 and 7b)

Scenario 7b was designed to determine the implications of higher rates of growth in electricity demand. Compared with the generation growth rates in Scenario 2,

Table 3-12

Cumulative Capital Costs of FGDs through 2000 under Scenarios 2 and 1

Type of Unit	Scenario 2			Scenario 1		
	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	26.2	2.12	81	59.6	6.00	101
NSPS	12.0	0.81	68	12.0	0.81	68
RNSPS	78.7	9.62	122	79.9	9.77	122
TOTAL	116.9	12.55	107**	151.5	16.58	109**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-13

Percentage Changes in Costs and Emissions under Stricter versus Base-Case SIPs (Scenario 1 versus Scenario 2)

	Percentage Change (Scenario 1/2)
Price of electricity	
(1985)	+9
(2000)	+1.5
Cumulative capital costs for FGDs	
(1976-2000)	+32
Cumulative revenues from ultimate consumers	
(1976-2000)	+4
SO_2 emissions	
(1985)	-51
(2000)	-41

those in Scenario 7b are higher after 1985. From 1985 to 2000, the ORBES counties experience an average generation growth rate of 3.7 percent per year under Scenario 7b, and of 2.1 percent per year under Scenario 2. By 1985 there is very little difference between the two scenarios;* but, by the year 2000, total generation under Scenario 7b exceeds that of Scenario 2 by 22 percent (907 TWh versus 741 TWh). We now discuss the impacts of this additional growth in generation after 1985.

Emissions

SO_2 emissions in the ORBES counties are not especially sensitive to higher rates of growth in electricity demand, because new plants will remove 85 to 90 percent of their SO_2. In the year 2000, the higher growth rates result in 4.71 million tons of SO_2 per year, versus 4.35 million tons under Scenario 2 (see Figure 3-12). By comparing Figure 3-13 with Figure 3-2, we see the increased generation between 1985 and 2000 that will come from plants subject to the 1979 RNSPS. These plants, which must remove about 90 percent of the sulfur from coal as mined, will use FGD and will emit at an average rate of about 0.6 lb $SO_2/10^6$ Btu. Generation from SIP plants is about the same under Scenario 7b as under Scenario 2, and emissions from these units will still predominate. The average complying SIP plant in the ORBES area will emit SO_2 at a rate of about 3.3 lb/10^6 Btu.

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* For Scenario 2, projected 1985 electricity generation in the ORBES counties was based largely on 1978 utility plans and generation growth rates as inter-preted by members of the Core Team. For Scenario 7b, 1979 projected utility generation growth rates as submitted to NERC were used to obtain a projection of the year 2000 generation if these higher-than-base-case growth rates were to occur. The resultant generation in 1985 in the ORBES counties under Scenario 7b is about 2.4 percent less than under Scenario 2, but by 2000 the total generation is 22 percent higher. The 1985 projections for the ORBES counties are essentially the same under the two scenarios, while the year 2000 projections reflect the difference in post-1985 demand growth.

Figure 3-12

Annual Electric Utility Coal-Plant SO_2 Emissions in the ORBES Counties under Scenarios 2 and 7b

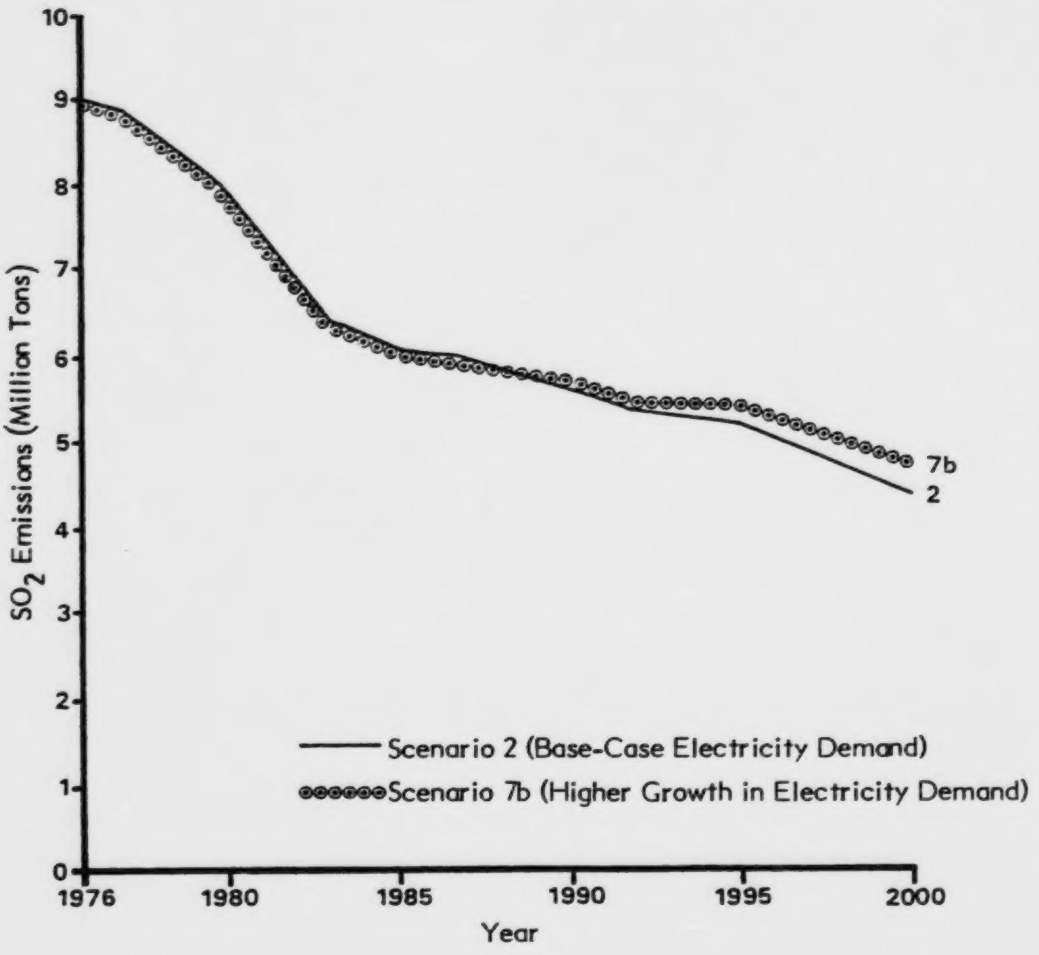
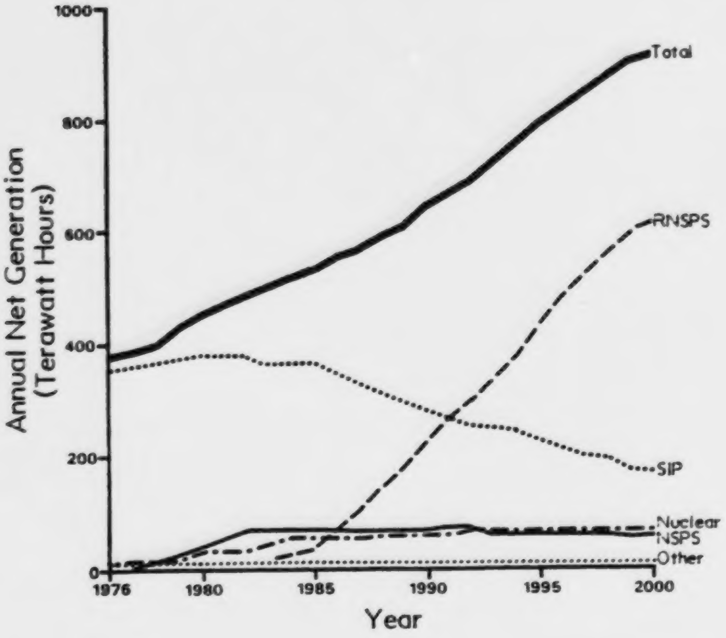
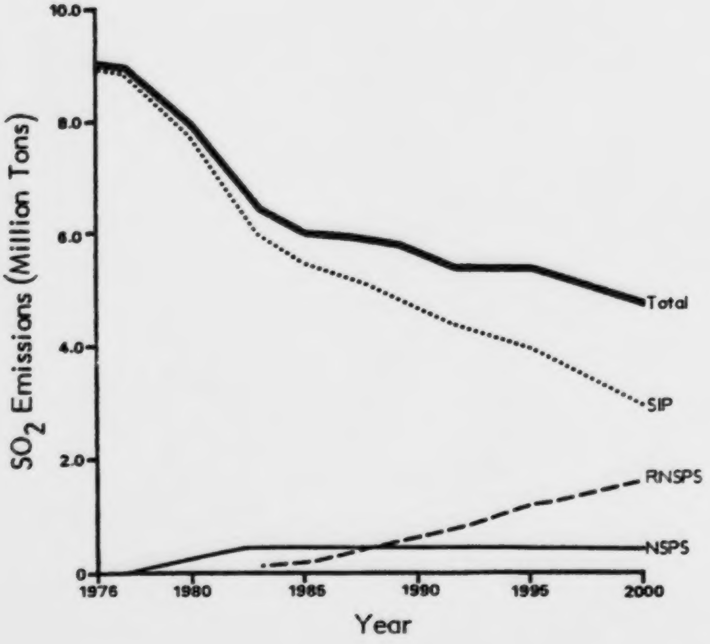


Figure 3-13

Annual Electric Utility Net Generation and Coal-Plant SO_2 Emissions in the ORBES Counties under Scenario 7b





Under Scenario 7b, annual NO_x emissions (Figure 3-14) increase from the 1976 level of 1.48 million tons to 2.46 million tons in the year 2000 (an increase of 66 percent). In comparison, under Scenario 2, annual NO_x emissions increase to 2 million tons by the year 2000 (an increase of 34 percent). Particulate emissions also are not especially sensitive to higher rates of growth in electricity demand. In the year 2000, particulate emissions total 0.21 million tons per year under Scenario 7b and 0.19 million tons per year under Scenario 2. Thus, higher demand growth rates increase particulate emissions by about 11 percent in the year 2000.

Prices

The projected price of electricity is about the same under the two scenarios through 1985, since demand growth is nearly identical (Figure 3-15). However, as greater amounts of new generating capacity are added to meet the higher demand growth rates, the price of electricity increases in Scenario 7b. By the year 2000, electricity prices total 5.7¢/kWh for Scenario 7b and 4.6¢/kWh for Scenario 2, a difference of about 24 percent. Cumulative revenues required from ultimate consumers are 22 percent higher under Scenario 7b ($639 billion versus $525 billion).

Capital Costs

Cumulative capital costs for FGDs through 2000 are 47 percent higher under Scenario 7b compared with Scenario 2 ($18.5 billion versus $12.6 billion). As for the cumulative capital costs of ESPs through 2000, these are about 25 percent higher under Scenario 7b compared with Scenario 2; ($7.7 billion versus $6.1 billion). (See Tables 3-14 and 3-15.)

Table 3-16 shows that the cumulative capital costs for new generating capacity through the year 2000 are about $33 billion more under Scenario 7b than Scenario 2 (an increase of about 49 percent). Both scenarios assume a 35-year retirement age for coal-fired units.

Figure 3-14

Annual Electric Utility Coal-Plant NO_x Emissions in the ORBES Counties under Scenarios 2 and 7b

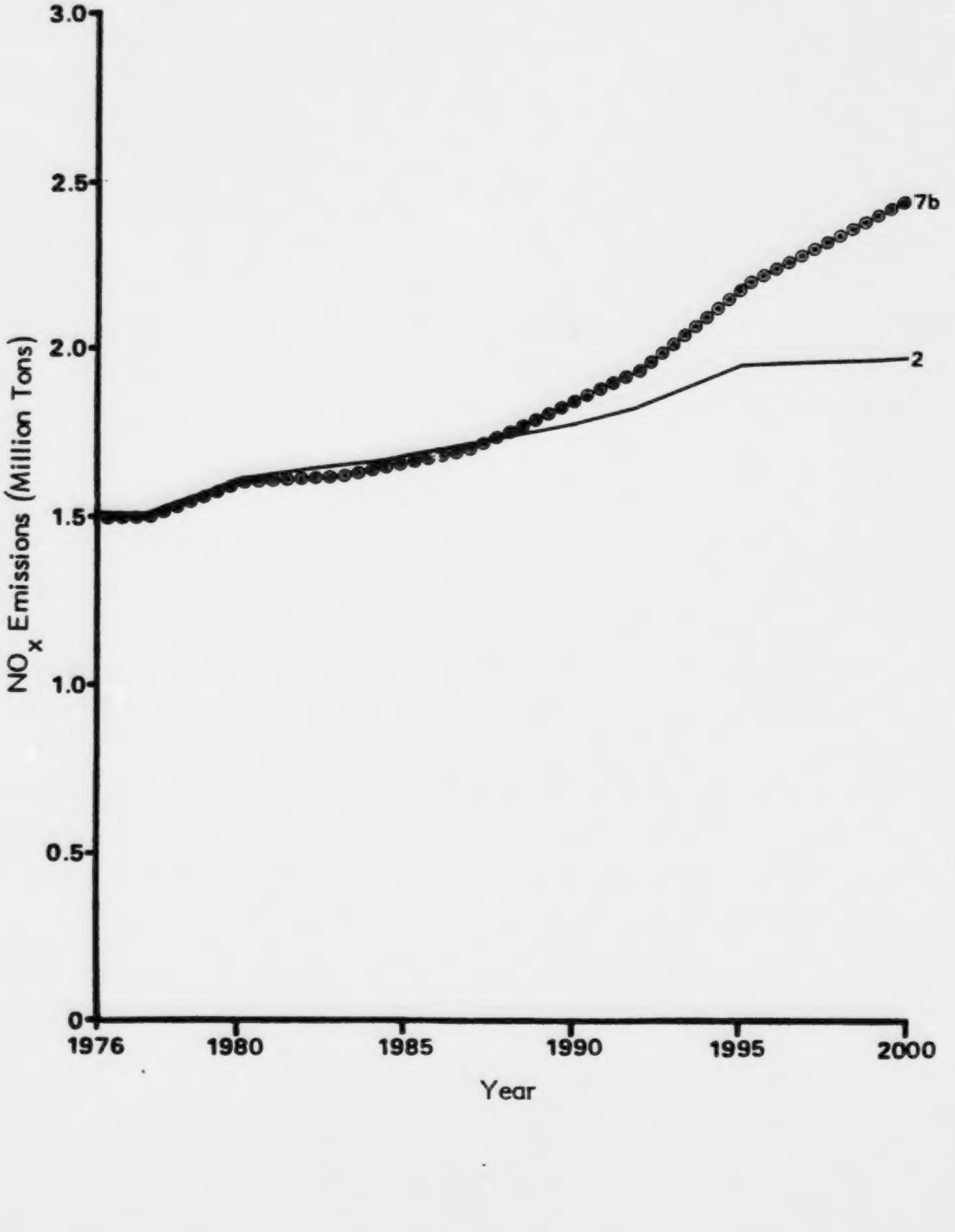
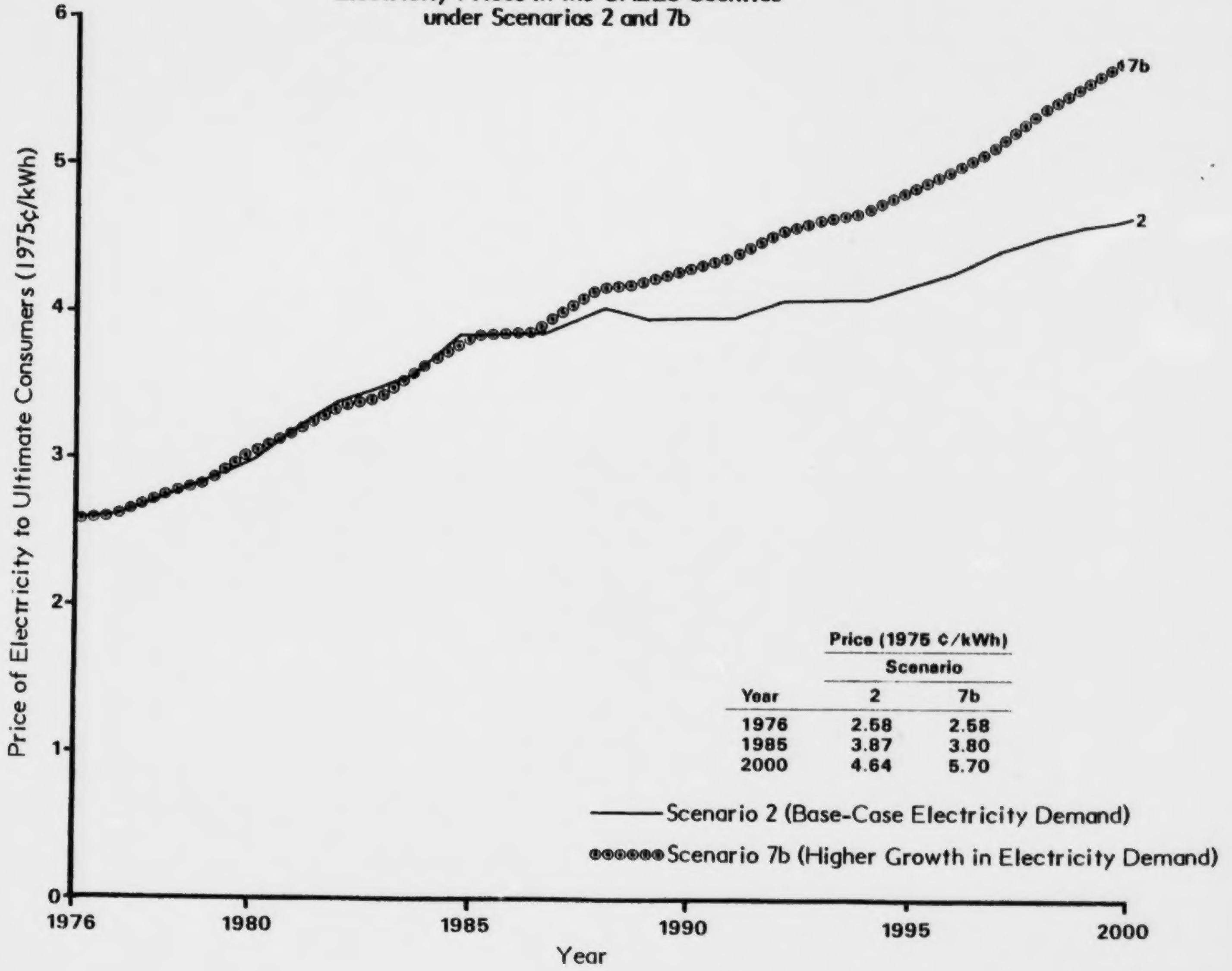


Figure 3-15

Electricity Prices in the ORBES Counties under Scenarios 2 and 7b



	Price (1975 ¢/kWh)	
	Scenario	
Year	2	7b
1976	2.58	2.58
1985	3.87	3.80
2000	4.64	5.70

Table 3-14

Cumulative Capital Costs of FGDs through 2000 under Scenarios 2 and 7b

	Scenario 2			Scenario 7b		
Type of Unit	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	26.2	2.12	81	26.2	2.12	81
NSPS	12.0	0.81	68	12.0	0.81	68
RNSPS	78.7	9.62	122	126.0	15.57	124
TOTAL	116.9	12.55	107**	164.2	18.50	113**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-15

Cumulative Capital Costs of ESPs through 2000 under Scenarios 2 and 7b

Type of Unit	Scenario 2			Scenario 7b		
	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	69.5	3.30	47	69.5	3.30	47
NSPS	12.0	0.34	28	12.0	0.34	28
RNSPS	78.7	2.48	32	126.0	4.03	32
TOTAL	160.2	6.12	38**	207.5	7.67	37**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-16

Cumulative Capital Costs of New Installed Generating Capacity through 2000 under Scenarios 2 and 7b

	Scenario 2			Scenario 7b		
Type of Unit	GW of New Installed Capacity*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of New Installed Capacity*	Cumulative Capital Costs (Billions of 1975$)	$/kW
Coal	95.5	67.02	702	141.0	100.04	710
Nuclear	9.8	8.27	846	9.8	8.23	842
TOTAL	105.3	75.29	715**	150.8	108.27	718**

* Before capacity penalties.

** Not a total; represents average $/kW.

Summary Comparison of Scenarios 2 and 7b

Higher rates of growth in electricity demand (Scenario 7b) will increase SO_2 emissions in the year 2000 by about 8 percent over the base-case moderate rates (Scenario 2). At the same time, under higher demand growth the price of electricity in the year 2000 will amount to about 5.7¢/kWh, a 23 percent increase over the base-case price of 4.64¢/kWh (see Table 3-17). Emissions of NO_x will further increase under higher demand growth by nearly 0.5 million tons in the year 2000 (a 23 percent increase). Cumulative revenues required from ultimate consumers over the 1976-2000 period will increase 22 percent, from $525 billion to $639 billion.

3.7 Sensitivity of Costs, Prices, and Emissions to Low Growth in Electricity Demand
(A Comparison of Scenarios 2 and 4)

Having discussed the implications of higher rates of growth in electricity demand, we now look at the implications of low rates. By comparing Scenarios 2 and 4, we can identify the sensitivity of costs, prices, and emissions to demand growth rates that are lower than those of the base case.

Emissions

As Figure 3-16 reveals, SO_2 emissions between 1976 and 2000 are not highly sensitive to lowered rates of growth in electricity demand. In 1985, SO_2 emissions amount to 5.7 million tons per year under Scenario 4 and to 6.1 million tons per year under Scenario 2 (a 7 percent reduction). By the year 2000, SO_2 emissions total 3.9 million tons per year under Scenario 4 and 4.4 million tons per year under Scenario 2 (an 11 percent reduction).

Intuitively, low growth implies correspondingly lower emissions. But how much lower? In 1985, net generation in the ORBES counties totals about 541 terawatt-hours under Scenario 2 but only about 440 terawatt-hours under Scenario 4.

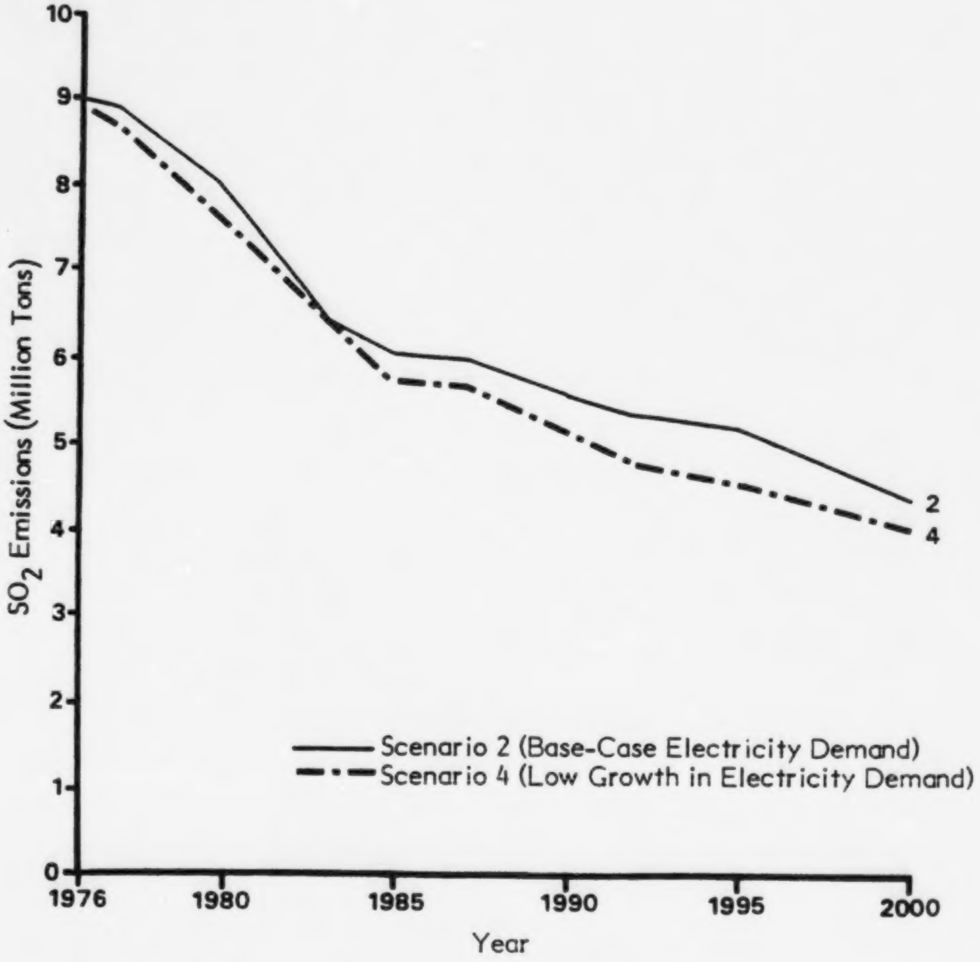
Table 3-17

Percentage Changes in Costs and Emissions under Higher versus Moderate Rates of Growth in Electricity Demand (Scenario 7b versus Scenario 2)

	Percentage Change (Scenario 7b/2)
Price of electricity (2000)	+23
Cumulative capital costs of FGDs (1976-2000)	+47
Cumulative capital costs of ESPs (1976-2000)	+25
Cumulative capital costs of new installed capacity (1976-2000)	+43
Cumulative revenues from ultimate consumers (1976-2000)	+22
SO_2 emissions (2000)	+8
NO_x emissions (2000)	+23
Particulate emissions (2000)	+10.5
Total generating capacity in ORBES (2000)	+31

Figure 3-16

Annual Electric Utility Coal-Plant SO_2 Emissions in the ORBES Counties under Scenarios 2 and 4



Thus, the low-growth scenario reduces net generation by nearly 19 percent. This 19 percent reduction in generation by 1985, however, achieves a reduction in SO_2 emissions of only 7 percent. This can be understood by referring to Figure 3-17, which shows annual net generation and SO_2 emissions under Scenario 4 by type of coal unit. Under low demand growth, fewer new units will come on line; yet, over time, the same capacity of existing units will remain available. Existing SIP units will generally be cheaper to operate than the units subject to the 1971 NSPS. Thus, although demand growth will be lower, this demand will still be met predominantly by SIP plants, which emit SO_2 at higher rates than newer units. Emission reductions will depend primarily on the scheduling of the newer, cleaner RNSPS coal capacity. Hence, lower demand growth by itself will not reduce emissions substantially.

NO_x emissions under Scenario 4 remain nearly level, at about 1.4 to 1.5 million tons per year, whereas in 1985, under Scenario 2, they rise to 1.71 million tons per year (Figure 3-18). By the year 2000, NO_x emissions still amount to 1.5 million tons under Scenario 4 but increase to 2.0 million tons under Scenario 2 (a 25 percent difference between the two scenarios). These differences arise from the additional NO_x emissions generated by new plants built under Scenario 2 but not needed under Scenario 4.

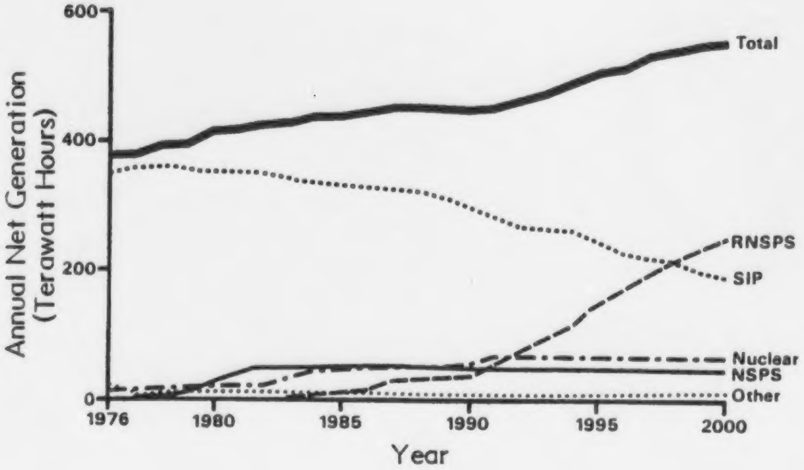
Particulate emissions are slightly lower under Scenario 4 than Scenario 2 — 0.22 million tons versus 0.25 million tons annually by 1985, and 0.16 million tons versus 0.19 million tons annually by the year 2000.

Prices

Just as higher demand growth leads to higher electricity prices, one would expect low demand growth to lead to lower electricity prices over the entire projection period. As Figure 3-19 shows, in 1985 the price of electricity reflects this expectation: 3.87¢/kWh under Scenario 2 but 3.62¢/kWh under Scenario 4. After 1985, the price under Scenario 4 is as much as 0.5¢/kWh lower than the

Figure 3-17

Annual Electric Utility Net Generation and Coal-Plant SO_2 Emissions in the ORBES Region under Scenario 4



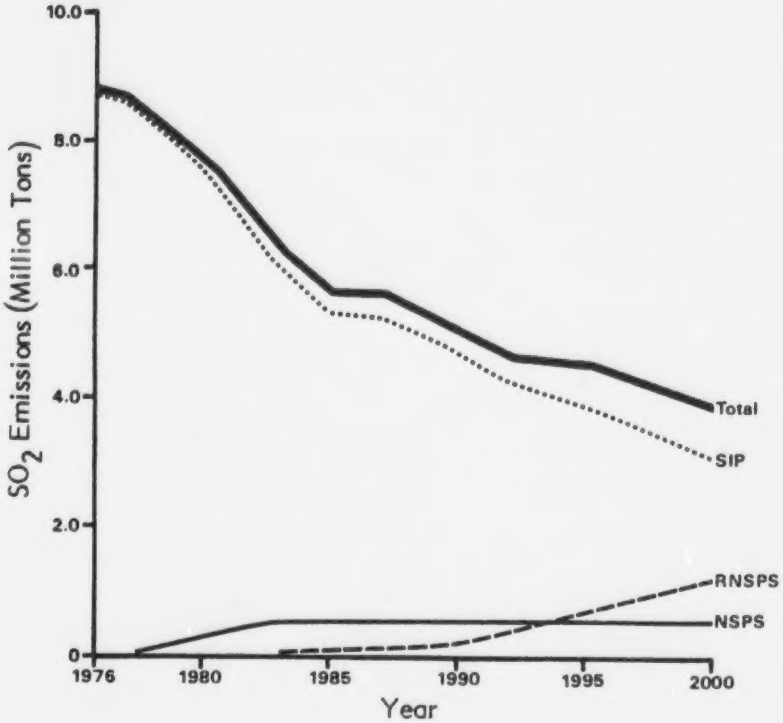


Figure 3-18

Annual Electric Utility Coal-Plant NO_x Emissions in the ORBES Counties under Scenarios 2 and 4

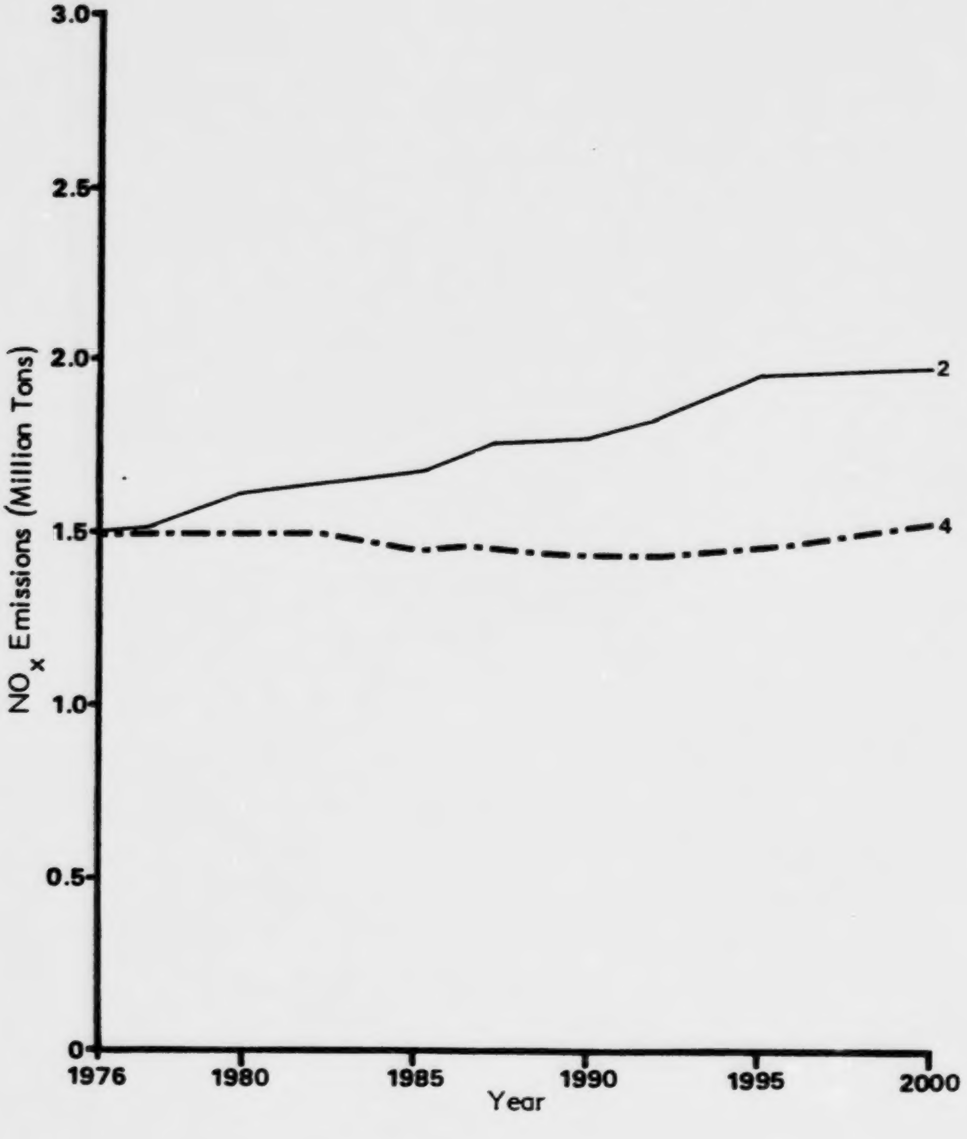
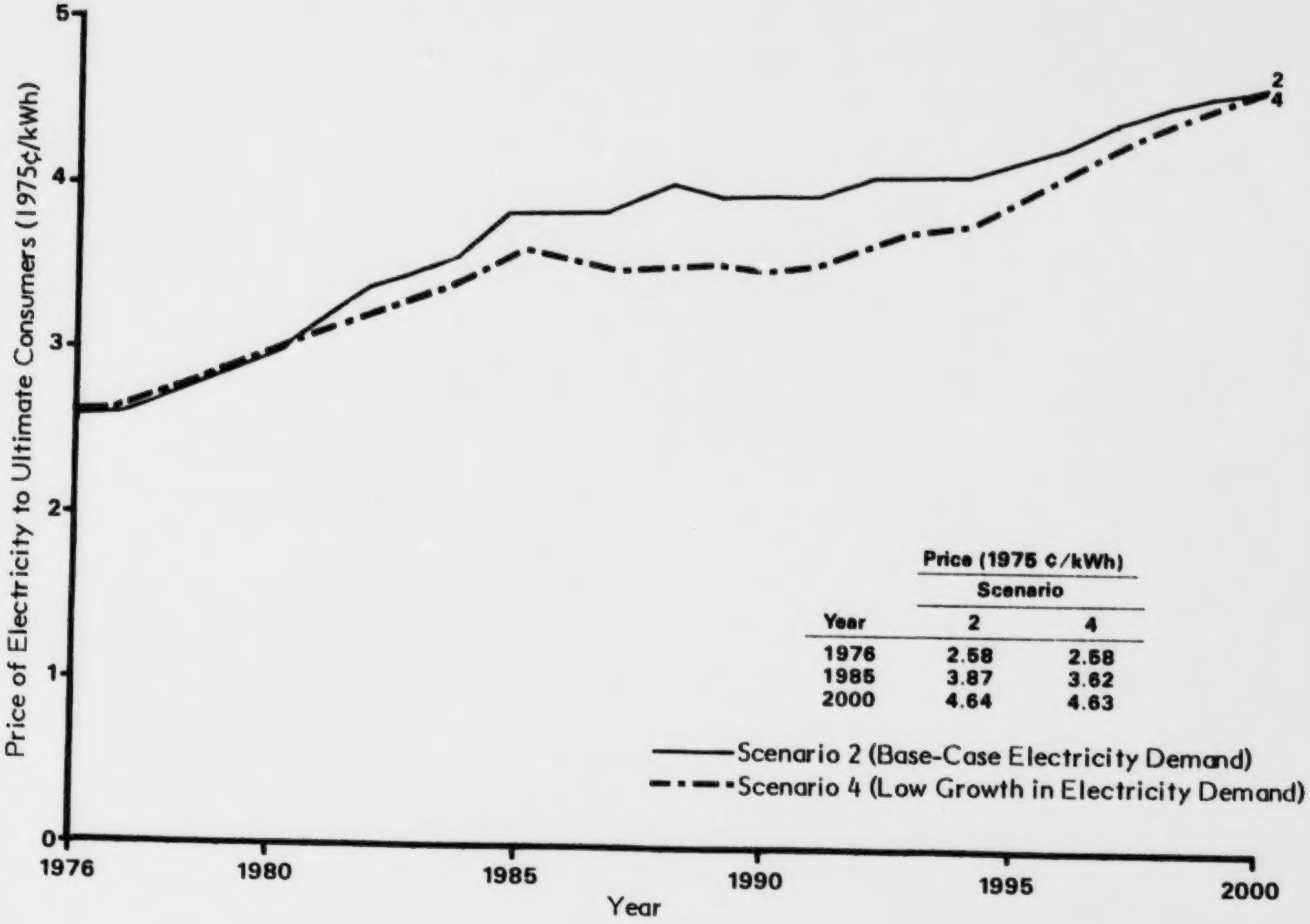


Figure 3-19

Electricity Prices in the ORBES Counties
under Scenarios 2 and 4



Year	Price (1975 ¢/kWh) Scenario 2	 4
1976	2.58	2.58
1985	3.87	3.62
2000	4.64	4.63

price under Scenario 2. However, by the year 2000, while the price of electricity amounts to 4.64¢/kWh under Scenario 2, it rises to 4.63¢/kWh under Scenario 4. Why, between 1985 and 2000, do electricity prices increase more rapidly in this projection under Scenario 4 than under Scenario 2?

In answer to the question we refer to Table 3-18, which shows annual average electricity growth rates for the two scenarios. These average growth rates were developed to meet the Core Team's specifications. For Scenario 2, demand growth was specified to average almost 4 percent per year prior to 1985, and 2.1 percent per year between 1985 and 2000. These specifications were met by allowing growth to taper off to below about 3 percent per year after 1985, to above 2 percent per year in the early 1990s, and to below 2 percent per year in the late 1990s, achieving a 2.1 percent per year compound average between 1985 and 2000. In comparison, electricity demand growth rates under low-growth Secnario 4 averaged about 1.6 percent per year. Thus, between 1995 and 2000 and after 2000, the growth in electricity demand is nearly the same for these two scenarios.

In Table 3-19 we show the gigawatts of capacity needed simply to replace retired capacity in the ORBES counties after 1995. This retired capacity is the same for both scenarios. The table also shows the total gigawatts of new capacity needed during the periods from 1995 to 2000 and from 2001 to 2005. Table 3-20, which lists the ratios of required additions per relative megawatt-hour of generation, shows that the ratio of capacity additions to generation after 1995 is greater in Scenario 4 than in Scenario 2.

The price of electricity is a function of total utility costs plus an allowed return on investment divided by total sales. Since the two scenarios have similar new-capacity costs, in the 1990s the price of electricity rises relatively more rapidly under Scenario 4, which has a smaller base of sales. In the year 2000, the prices per kilowatt-hour under the two scenarios become nearly equivalent, although far fewer kWh are being generated under Scenario 4.

Table 3-18

Compound Annual Average Rates of Growth in Electricity Demand Rates under Scenarios 2 and 4 (Percent per Year)

Period	Scenario 2	Scenario 4
1985-2000	2.10	1.60

Table 3-19

Post-1995 Capacity Additions Required to Meet Demand under Scenarios 2 and 4

	Scenario 2				Scenario 4			
Year	Required Capacity (GW)	Five-Year Additions Due to Demand (GW)	Five-Year Additions Due to Retirements (GW)	Five-Year Total Additions Required (GW)	Required Capacity (GW)	Five-Year Additions Due to Demand (GW)	Five-Year Additions Due to Retirements (GW)	Five-Year Total Additions Required (GW)
1995	146.6				110.0			
2000	158.1	11.5	7.5	19.0	120.6	10.6	7.5	18.1
2005	170.5	12.4	16.5	28.9	132.2	11.6	16.5	28.1

Table 3-20

Capacity Additions Required/Relative* MWh under Scenarios 2 and 4

Period	Scenario 2	Scenario 4
1996-2000	19/100 = .19	18.1/75 = .24
2001-2005	28.9/110 = .26	28.1/82 = .34

* Megawatt-hours under each scenario were indexed so that generation in the year 2000 would equal 100 under Scenario 2.

As expected, over the entire 1976-2000 period, average electricity prices and projected cumulative revenues needed from ultimate consumers are considerably lower under the case of low growth in electricity demand ($390 billion under Scenario 4 versus $525 billion under Scenario 2, a reduction of 26 percent).

Capital Costs

Table 3-21 shows the cumulative capital costs for flue gas desulfurization systems for the two scenarios. Under Scenario 4, $8.7 billion are required to build FGDs for 81.7 GW of capacity. Under Scenario 2, $12.6 billion are required to build FGDs for 117 GW of capacity. Table 3-22 shows the cumulative capital costs for ESPs: under Scenario 4, about $5.1 billion are required to construct ESPs for 125 GW of capacity; and under Scenario 2, about $6.1 billion are required to construct ESPs for 160 GW of capacity.

Similarly, Table 3-23 shows the cumulative capital costs of new generating capacity. As can be seen, less coal capacity is built under Scenario 4 than under Scenario 2. Under Scenario 4, 59 GW of coal capacity come on line by 2000 to satisfy demand as well as to replace retired SIP capacity. The capital cost of this new coal capacity amounts to about $40.9 billion. Under Scenario 2, 95.5 GW of new coal capacity are built at a cost of $67 billion. The capital costs per kW of new capacity are slightly higher under the low-growth scenario because of the cost escalation due to longer nuclear-unit deferrals occurring under the low-growth projection.

Summary Comparison of Scenarios 2 and 4

Low growth in electricity demand (Scenario 4) reduces regional SO_2 emissions in the year 2000 by about 9.5 percent below the base-case projections of Scenario 2. Capital costs for FGDs are 31 percent lower under Scenario 4 compared with Scenario 2. (See Table 3-24.)

Table 3-21

Cumulative Capital Costs of FGDs through 2000 under Scenarios 2 and 4

Type of Unit	Scenario 2			Scenario 4		
	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	26.2	2.12	81	26.2	2.12	81
NSPS	12.0	0.81	68	8.9	0.62	70
RNSPS	78.7	9.62	122	46.6	5.97	128
TOTAL	116.9	12.55	107**	81.7	8.71	107**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-22

Cumulative Capital Costs of ESPs through 2000 under Scenarios 2 and 4

	Scenario 2			Scenario 4		
Type of Unit	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	69.5	3.30	47	69.5	3.30	47
NSPS	12.0	0.34	28	8.9	0.25	28
RNSPS	78.7	2.48	32	46.6	1.50	32
TOTAL	160.2	6.12	38**	125.0	5.05	40**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-23

Cumulative Capital Costs of New Installed Generating Capacity through 2000 under Scenarios 2 and 4

Type of Unit	Scenario 2			Scenario 4		
	GW of New Installed Capacity*	Cumulative Capital Costs (Billions of 1975$)	$/kW**	GW of New Installed Capacity*	Cumulative Capital Costs (Billions of 1975$)	$/kW**
Coal	95.5	67.02	702	59.0	40.94	694
Nuclear	9.8	8.27	846	9.8	8.66	886
TOTAL	105.3	75.29	715$^+$	68.8	49.60	721$^+$

* Before capacity penalties.

** Capital costs per kW for nuclear units are slightly higher for Scenario 4 than for Scenario 2 due to longer unit deferral and resultant cost escalation.

+ Not a total; represents average $/kW.

Table 3-24

Percentage Changes in Costs and Emissions under Low versus Moderate Rates of Growth in Electricity Demand (Scenario 4 versus Scenario 2)

	Percentage Change (Scenario 4/2)
Price of electricity	
(1985)	-6.5
(2000)	-0.2
Cumulative capital costs of FGDs (1976-2000)	-31
Cumulative capital costs of ESPs (1976-2000)	-18
Cumulative capital costs of new generating capacity (1976-2000)	-34
Cumulative revenues from ultimate consumers (1976-2000)	-26
SO_2 emissions	
(1985)	-7
(2000)	-9.5
Particulate emissions	
(1985)	-12
(2000)	-16
Total generating capacity (2000)	-24
NO_x Emissions	
(1985)	-16
(2000)	-25

Over the period from 1976 through 2000, cumulative revenues required from ultimate consumers under Scenario 4 total about \$390 billion, or 26 percent less than cumulative revenues under the base case.

3.8 Sensitivity of Costs, Prices, and Emissions to Generating-Unit Lifetimes (A Comparison of Scenarios 7 and 7b)

With SIP compliance, SO_2 emissions in 2000 will fall below 1976 levels. How far they decline, however, will be a function of coal-unit retirement schedules. In each scenario discussed so far, coal-fired generating units were assumed to have a lifetime of 35 years (as specified by the ORBES Core Team). Scenario 7 was designed to test the sensitivity of costs, prices, and emissions to 45-year unit lifetimes. The only change in assumptions between Scenario 7 and Scenario 7b is the retirement age for coal units — 45 years for Scenario 7, 35 years for Scenario 7b. By the year 2000, about 16 less gigawatts of SIP capacity are operating under Scenario 7b than under Scenario 7. This deficit is made up by the addition of new coal-fired RNSPS units.

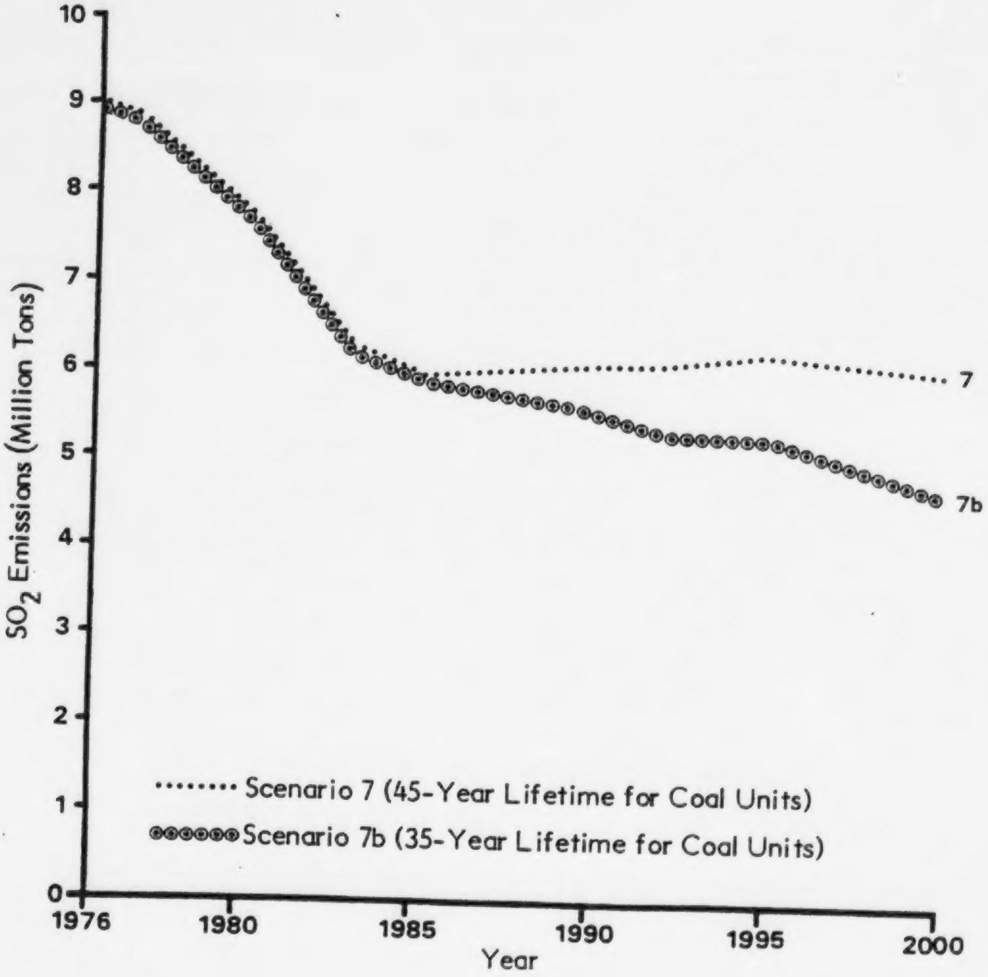
Emissions

Under the longer coal-unit lifetimes of Scenario 7, annual SO_2 emissions decrease from the 1976 level of 8.94 million tons to 6.06 million tons in 2000; under Scenario 7b, they decrease to 4.71 million tons in 2000. Thus, a 10-year increase in generating-unit lifetimes in the ORBES counties increases annual SO_2 emissions in the year 2000 by about 29 percent. (See Figure 3-20.)

After SIP compliance occurs, it is the retirement rate of existing units that largely determines the rate at which SO_2 emissions decrease. Indeed, under the assumption of a 35-year unit lifetime, SO_2 emissions decrease after 1985. However, under a 45-year lifetime, SO_2 emissions remain nearly constant between 1985 and 2000. If average service lives were to last longer than 45 years, SO_2 emissions could rise between 1985 and 2000, depending on the rate of new capacity additions.

Figure 3-20

Annual Electric Utility Coal-Plant SO_2 Emissions in the ORBES Counties under Scenarios 7 and 7b



In Figure 3-21, annual net generation and SO_2 emissions by type of coal unit are shown for the two scenarios. In the year 2000, generation from SIP units is greater under Scenario 7 than under Scenario 7b. Since SIP units dominate in the production of ORBES county emissions, it is expected that longer generating-unit lifetimes will result in greater SO_2 emissions.

NO_x emissions in the ORBES counties are not highly sensitive to generating-unit lifetimes. By the year 2000, annual NO_x emissions amount to about 2.63 million tons under Scenario 7 and to about 2.46 million tons under Scenario 7b (a difference of about 7 percent). However, as shown in Figure 3-22, total emitted particulates can be sensitive to this variation. By the year 2000, annual particulate emissions total 0.26 million tons under Scenario 7 and 0.21 million tons under Scenario 7b (a decrease of nearly 20 percent because of the shorter unit lifetime). However, when viewed in relation to 1976 particulate levels, the differences between Scenario 7 and 7b are put in perspective (-81 percent versus -85 percent).

Prices

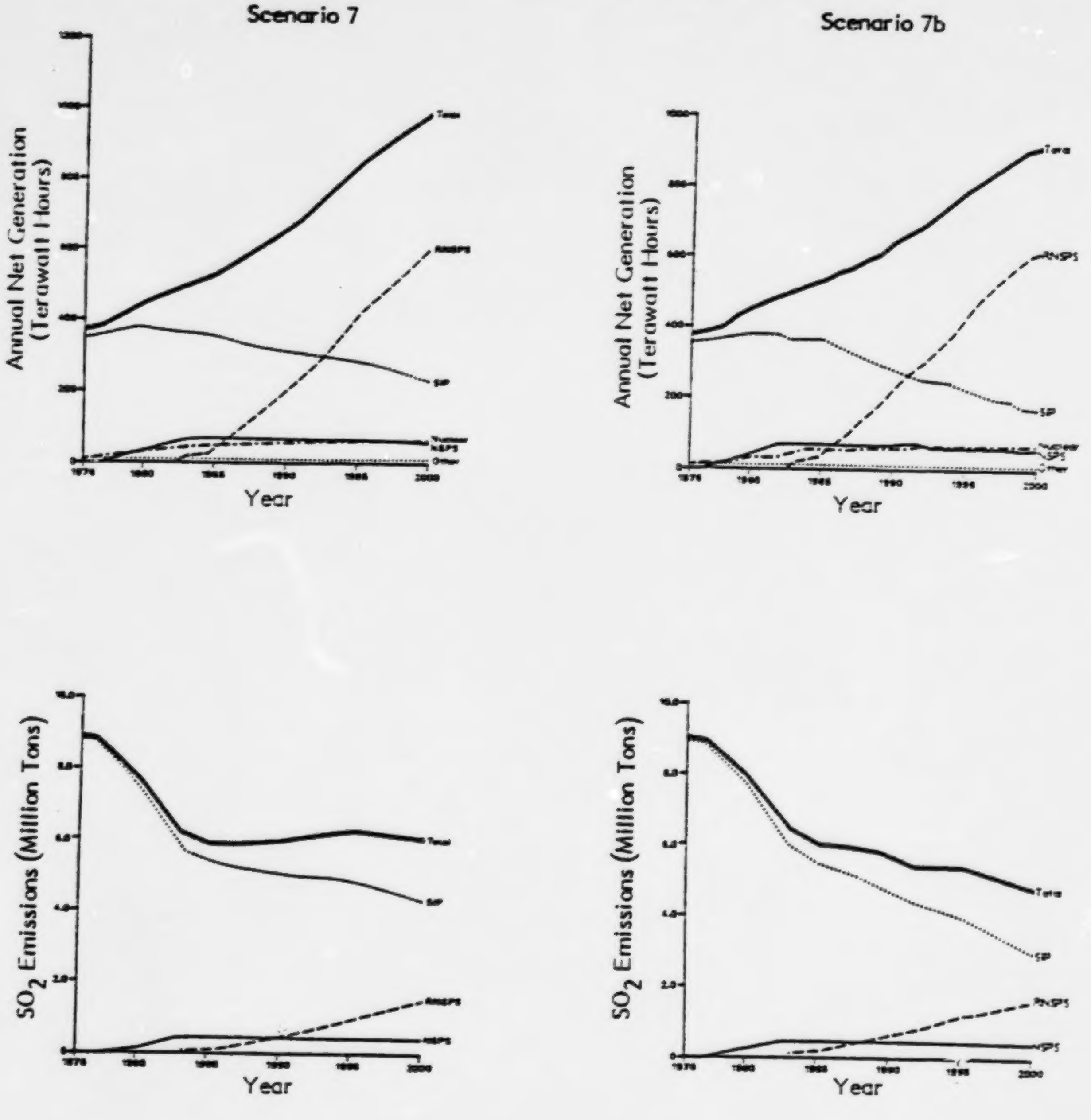
Under the higher demand growth conditions that characterize both scenarios, the difference in generating-unit lifetime does not lead to a large percentage change in the price of electricity. In the year 2000, electricity prices total 5.71¢/kWh under Scenario 7b and 5.53¢/kWh under Scenario 7 (a decrease of about 3 percent due to the shorter unit lifetime). (See Figure 3-23.) The cumulative revenues required from ultimate consumers over the 1976-2000 period decrease from $639 billion under Scenario 7b to $617 billion under Scenario 7 (a 4 percent reduction).

Costs

In Tables 3-25, 3-26, and 3-27, cumulative capital costs for FGDs, ESPs, and new coal-fired capacity are summarized for the two scenarios. The assumption

Figure 3-21

Annual Electricity Utility Net Generation and Coal-Plant SO_2 Emissions in the ORBES Counties under Scenarios 7 and 7b[2]


Scenario 7

Scenario 7b

Figure 3-22

Annual Electric Utility Coal-Plant Particulate Emissions in the ORBES Counties under Scenarios 7 and 7b

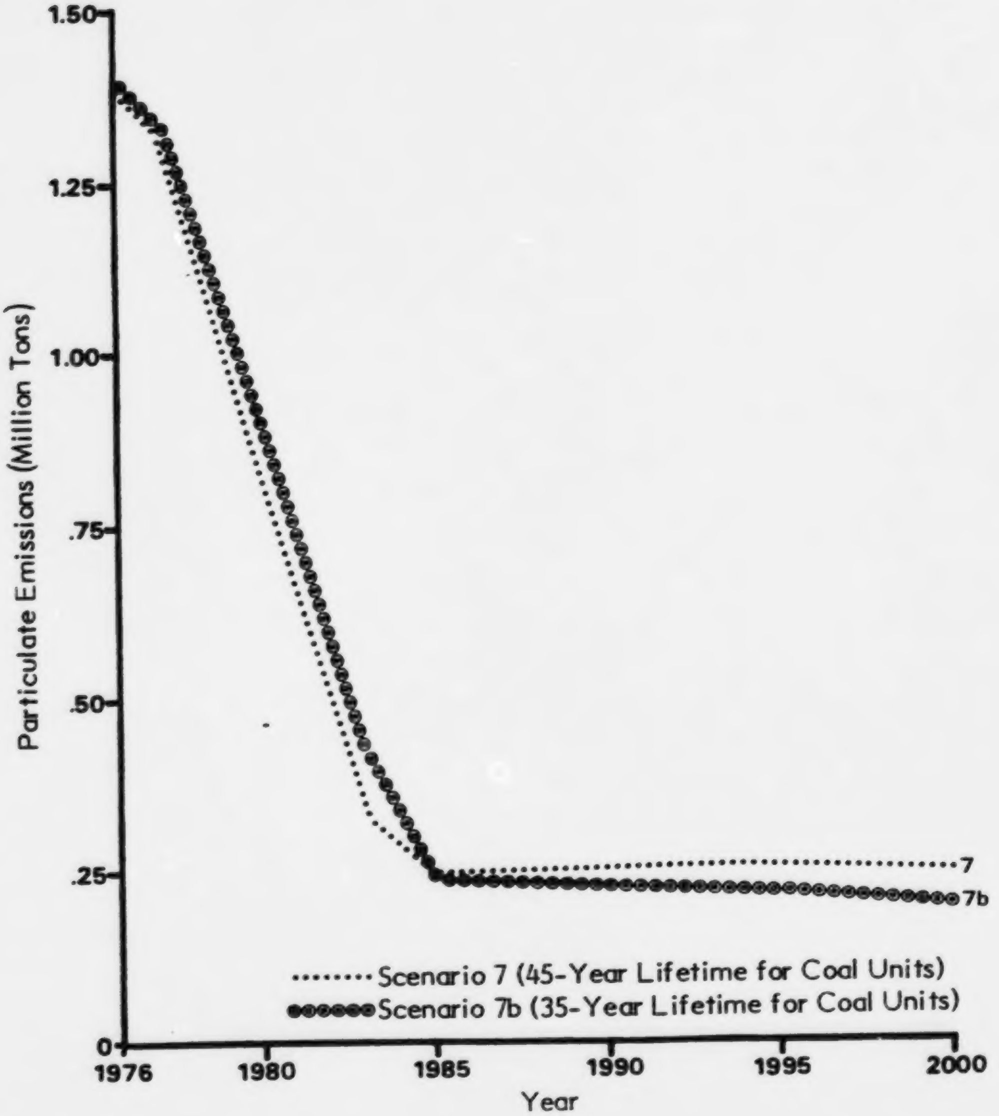
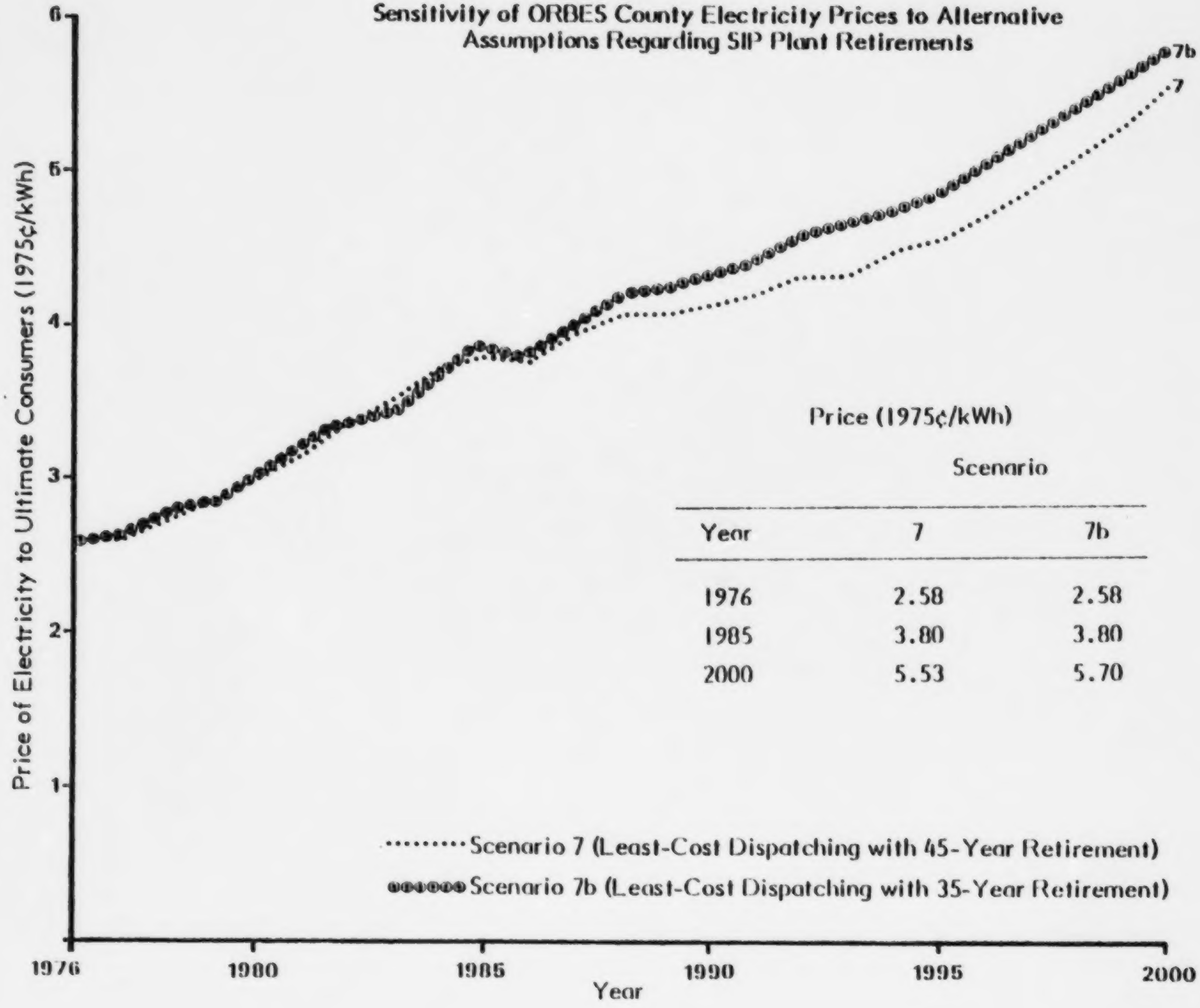


Figure 3-23

Sensitivity of ORBES County Electricity Prices to Alternative Assumptions Regarding SIP Plant Retirements



Price (1975¢/kWh)

	Scenario	
Year	7	7b
1976	2.58	2.58
1985	3.80	3.80
2000	5.53	5.70

Table 3-25

Cumulative Capital Costs of FGDs through 2000 under Scenarios 7 and 7b

	Scenario 7			Scenario 7b		
Type of Unit	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with FGDs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	26.2	2.12	81	26.2	2.12	81
NSPS	12.0	0.81	68	12.0	0.81	68
RNSPS	112.2	13.85	123	126.0	15.57	124
TOTAL	150.4	16.78	112**	164.2	18.50	113**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-26

Cumulative Capital Costs of ESPs through 2000 under Scenarios 7 and 7b

Type of Unit	Scenario 7			Scenario 7b		
	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of Capacity with ESPs*	Cumulative Capital Costs (Billions of 1975$)	$/kW
SIP	69.5	3.30	47	69.5	3.30	47
NSPS	12.0	0.34	28	12.0	0.34	28
RNSPS	112.2	3.40	30	126.0	4.03	32
TOTAL	193.7	7.04	36**	207.5	7.67	37**

* After capacity penalty.

** Not a total; represents average $/kW.

Table 3-27

Cumulative Capital Costs of New Installed Generating Capacity through 2000 under Scenarios 7 and 7b

Type of Unit	Scenario 7			Scenario 7b		
	GW of New Installed Capacity*	Cumulative Capital Costs (Billions of 1975$)	$/kW	GW of New Installed Capacity*	Cumulative Capital Costs (Billions of 1975$)	$/kW
Coal	127.7	90.38	708	141.0	100.04	710
Nuclear	9.8	8.23	842	9.8	8.23	842
TOTAL	137.5	98.61	717**	150.8	108.27	718**

* Before capacity penalties.

** Not a total; represents average $/kW.

of a longer coal-unit lifetime (Scenario 7) reduces cumulative capital requirements for FGDs and ESPs together by about \$2.23 billion, and cumulative capital requirements for new capacity by about \$9.7 billion.

Summary Comparison of Scenarios 7 and 7b

Relative SO_2 and particulate emission levels in the ORBES counties increase substantially under the assumption of a longer generating-unit lifetime. As shown in Table 3-28, annual SO_2 emissions in the year 2000 are 28.5 percent higher under Scenario 7 compared with Scenario 7b. Similarly, total emitted particulate levels are higher by about 24 percent. The trade-off for these higher emissions is felt in lower costs and prices. The price the consumer pays for electricity in the year 2000 is about 3 percent lower under Scenario 7 compared with 7b; and cumulative capital costs are about 9 percent lower.

Under current circumstances, 45-year coal unit lifetimes could become representative. Extending the life of existing units would reduce utility costs and, for a time, avoid the difficulties of siting and licensing replacement capacity. However, prolonging the retirement age of SIP units would significantly reduce the likelihood of achieving potential SO_2 emission reductions between 1985 and 2000.

3.9 Sensitivity of Costs, Prices, and Emissions to Alternative Dispatching Criteria

As pointed out earlier, generating units are typically loaded in order of increasing costs, i.e., according to a least-cost dispatching criterion. Thus, since baseload units are cheaper to operate, they are generally used to generate more electricity. Scenario 7a was designed to test the sensitivity of costs (measured in the form of electricity prices to ultimate consumers) and emissions to a least-emissions dispatching criterion. By comparing Scenarios 7 and 7a, we can gauge

Table 3-28

Percentage Changes in Costs and Emissions under 45-Year versus 35-Year Coal Unit Lifetimes (Scenario 7 versus Scenario 7b)

	Percentage Change (Scenario 7/7b)
Price of electricity (2000)	-3
Cumulative capital costs of FGDs (1976-2000)	-9
Cumulative capital costs of ESPs (1976-2000)	-7
Cumulative capital costs of new installed capacity (1976-2000)	-9
Cumulative revenues from ultimate consumers (1976-2000)	-4
SO_2 emissions (2000)	+28.5
Particulate emissions (2000)	+24
NO_x emissions (2000)	+7
Total generating capacity (2000)	+1

the potential effects of such a strategy and see whether further study of such an option is warranted.

Under the least-emissions dispatching strategy, applied only to coal plants, these plants are operated in order of least emissions per million Btu of fuel consumed. Thus, new coal units meeting the 1979 NSPS (RNSPS) are always dispatched before units subject to the 1971 NSPS, and the 1971 NSPS units, in turn, are always dispatched before SIP-regulated units with limits higher than 1.2 lb $SO_2/10^6$Btu. In contrast, under the more usual least-cost dispatching strategy (Scenario 7), coal units are loaded in order of increasing variable costs (including fuel and variable operating and maintenance for pollution control devices, etc.). In some circumstances the least-cost strategy can lead to older, dirtier plants being dispatched before newer, cleaner plants. If two plants burn similarly priced coals but one has a scrubber to meet a more stringent SO_2 standard, the plant without the scrubber will usually be cheaper to operate. Thus, there is interest in investigating a least-emissions dispatching strategy.

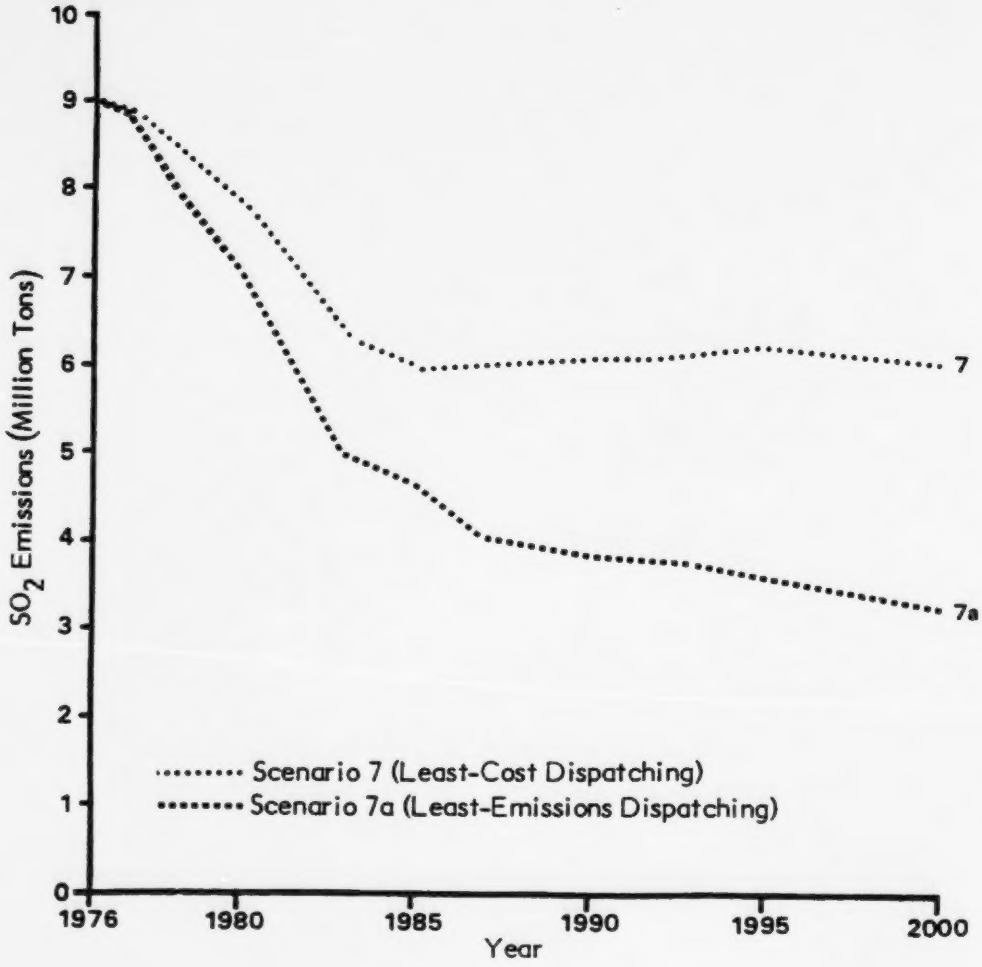
Under the usual least-cost dispatching strategy, plants are generally loaded in the following order: baseload hydro, nuclear, coal, combined cycle, gas steam, oil steam, peaking hydro or pumped storage, and combustion turbines. Variations will depend, for example, on specific unit and fuel characteristics, system composition, the location of plants in the grid, scheduled and unscheduled outages, and hourly loads. Since coal units comprise the bulk of the system in the ORBES counties, coal plants will be used to meet base and intermediate loads and some portion of peak loads.

Emissions

Figure 3-24 shows SO_2 emissions over time for the two scenarios. Under Scenario 7 (least-cost dispatching), SO_2 emissions in 1985 decrease to 5.93 million tons per year; under Scenario 7a (least-emissions dispatching), they decrease to 4.69 million tons per year. By the year 2000 the difference is greater because of the large RNSPS capacity on line: the SO_2 emission levels under Scenario 7a (3.34 million tons per year) are 45 percent lower than the levels under Scenario 7.

Figure 3-24

Annual Electric Utility Coal-Plant SO_2 Emissions in the ORBES Counties under Scenarios 7 and 7a



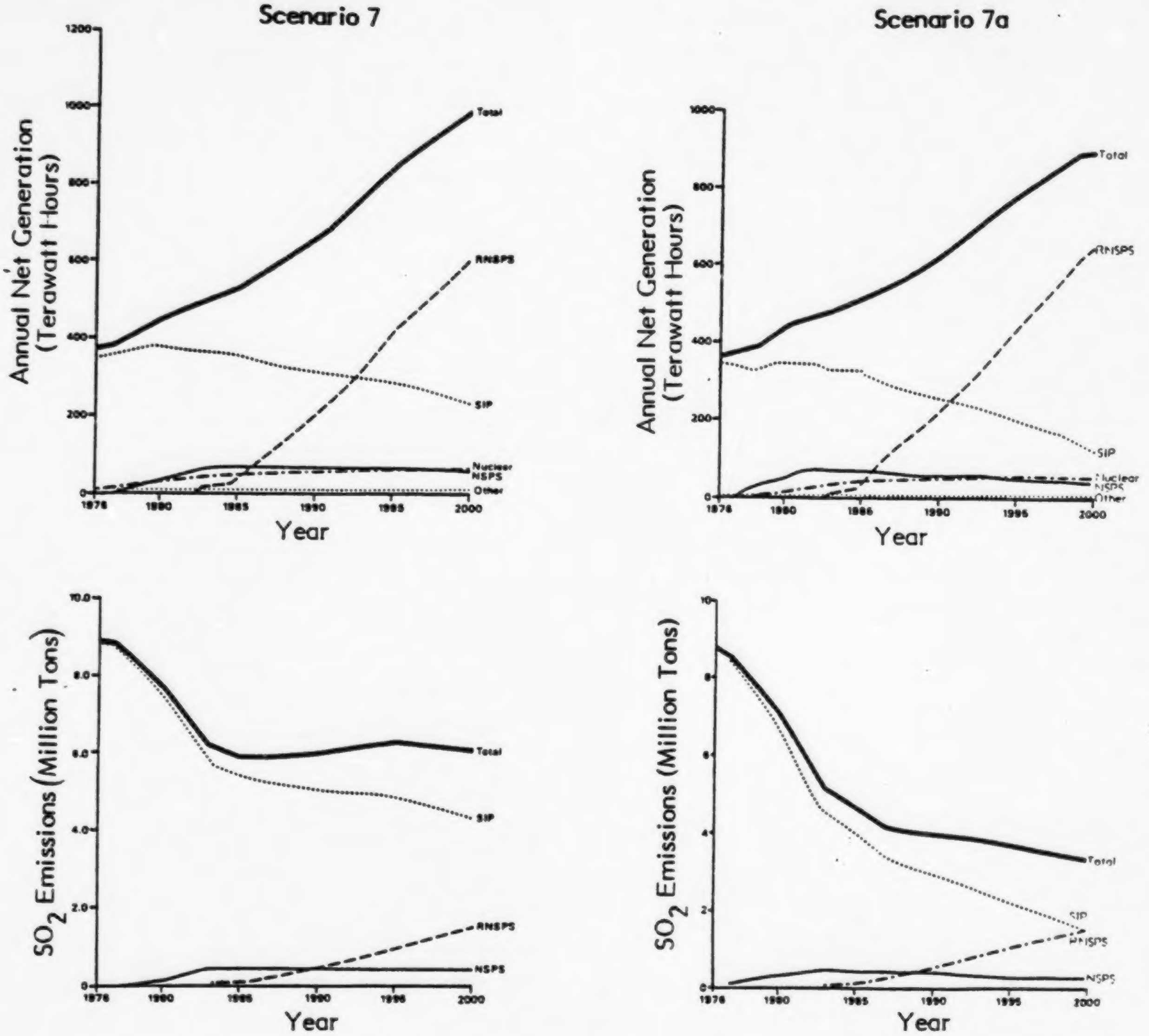
The decrease is attributable to the least-emissions dispatching criterion. This can be best understood by comparing emissions by type of coal units and their generation. As Figure 3-25 shows, under the least-emissions criterion by the year 2000, the SIP-unit share of the load has decreased considerably, whereas the RNSPS-unit share has increased.

Under Scenario 7, the least-cost dispatching scenario, RNSPS and NSPS units in the year 2000 generate 628 TWh at an average dispatched capacity factor of 0.58; SIP units in the same year generate about 239 TWh at an average capacity factor of 0.43. Under Scenario 7a, the mandatory baseloading of RNSPS units under the least-emissions dispatching strategy increases RNSPS and NSPS generation to 698 TWh, an increase of 70 TWh. The average capacity factor for these units rises to 0.64. This additional generation from RNSPS and NSPS plants reduces SIP-plant generation by 70 TWh, or 30 percent. This alone provides a large (30 percent) emission reduction. In addition, because the proportion of high-emission SIP capacity in the ORBES counties is greater than that in utility service areas that encompass counties in the surrounding region, some generation is shifted to plants outside the ORBES counties. In other words, for the same consumer electricity demand in the utility service areas in and around the ORBES area, a least-emissions dispatching strategy tends to reduce the proportion of generation that occurs in the ORBES counties. Furthermore, since the largest emitters (on the basis of pounds of SO_2 per 10^6 Btu) are loaded last, SIP-plant emissions are reduced by more than the proportional reduction in generation under the least-emissions dispatch strategy. It should be remembered that SIP plants in the ORBES counties will emit an average of five to six times more SO_2 on a per-Btu basis than RNSPS plants will. Indeed, the dirtiest SIP plants may emit nine to ten times more.

NO_x emissions by the year 2000 differ slightly under the two scenarios — 2.63 million tons per year under Scenario 7, and 2.41 million tons per year under Scenario 7a (an 8.4 percent decrease). Similarly, annual particulate emissions in 2000 decrease from 0.26 million tons under Scenario 7 to 0.21 million tons under Scenario 7a (a 19 percent decrease).

Figure 3-25

Annual Net Generation and SO_2 Emissions in the ORBES Counties by Type of Coal Plant under Scenarios 7 and 7a



These results suggest that the feasibility of implementing a least-emissions dispatching strategy should be examined in greater detail. It should be noted, however, that under lower demand growth fewer new plants will be available for mandatory baseloading, reducing the overall efficacy of the strategy. It should also be noted that the dispatching algorithms used deterministic rather than probabilistic coal-unit availabilities for this initial comparison. Given the sensitivity of individual coal-unit availability to such factors as unit size, unit age, and the potentially variable reliability of FGD scrubbing modules, and given the promise of least-emissions dispatching for reducing emissions, a more detailed probabilistic analysis of the least-emissions strategy is warranted.

Prices

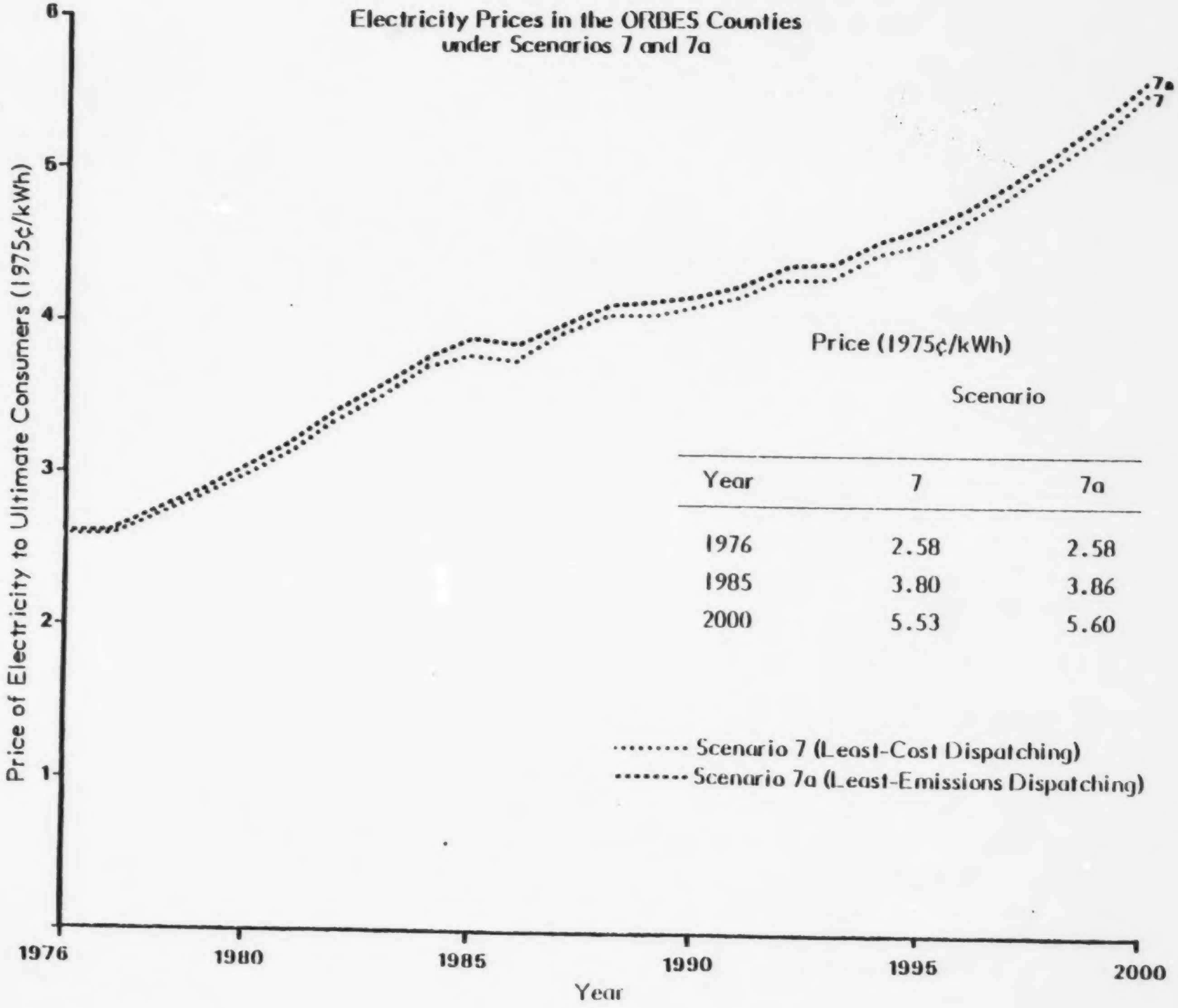
Figure 3-26 reveals that the price of electricity is fairly insensitive to a least-emissions dispatching criterion. Thus, in 1985 the price of electricity amounts to 3.8¢/kWh under Scenario 7 and to 3.86¢/kWh under Scenario 7a (a 1.6 percent increase for least-emissions dispatching). By the year 2000, the percentage difference is smaller – 5.53¢/kWh under Scenario 7 versus 5.6¢/kWh under Scenario 7a (a 1.3 percent increase). This small increase in price reflects the fact that the simulated differences between these scenarios affect only the operating and maintenance costs and fuel costs of essentially the same generating systems. Cumulative revenues required from ultimate consumers over the 1976-2000 period are about $9 billion higher under Scenario 7a.

Costs

Since the same generating systems are being operated under both dispatching options, the capital costs of FGDs, ESPs, and new generating units are the same. The major differences in costs are due to the increased operation and maintenance of pollution control devices and the increased fuel costs encountered under least-emissions dispatching (the impacts of which are revealed in price and revenue sensitivities).

Figure 3-26

Electricity Prices in the ORBES Counties
under Scenarios 7 and 7a



Price (1975¢/kWh)

	Scenario	
Year	7	7a
1976	2.58	2.58
1985	3.80	3.86
2000	5.53	5.60

Summary Comparison of Scenarios 7 and 7a

As Table 3-29 shows, for a slight increase in cost to the consumer (about 2 percent), significant decreases in SO_2 emissions (perhaps up to 45 percent) may be achieved in the ORBES counties. Before further conclusions are reached, a probabilistic analysis should be made of the least-emissions dispatching strategy, and an examination should be made of issues relating to the reliability of specific systems

3.10 Forecasts of the Demand for Electricity in the ORBES Counties

In some of the preceding projections we examined the implications of alternative demand growth scenarios. Because of rapidly changing costs of fuel and other factors, electricity prices are rising. How will these price increases affect the growth of electricity demand? And how will future income levels affect the use of electricity?

In Appendix C we discuss the difficulty of forecasting electricity demand; then we proceed to develop a simple econometric equation to forecast electricity demand in the ORBES area.

Here we present the results of applying the demand forecasting method described in Appendix C. Using that method, we applied the USM to forecast price- and income-sensitive demand for the ORBES counties. Our demand estimates are based on prices forecast by the USM FINANCIAL module for privately owned electric utilities in these counties. In the paragraphs that follow we present the forecast results using the Witt elasticities* (-0.79 for the price elasticity and +0.97 for the income elasticity).

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* Two sets of elasticity estimates were used to derive the coefficients in equation (1) given in Appendix C. No significant difference in the demand forecasts resulted from using the two sets of estimates. See Appendix C for a more detailed discussion.

Table 3-29

Percentage Changes in Costs and Emissions under a Least-Emissions versus Least-Cost Dispatching Strategy (Scenario 7a versus Scenario 7)

	Percentage Change (Scenario 7a/7)
Price of electricity	
(1985)	+1.5
(2000)	+1
Cumulative revenues from ultimate consumers	
(1976-2000)	+1.5
SO_2 emissions	
(1985)	-21
(2000)	-45
NO_x emissions	
(1985)	-5
(2000)	-8.5
Particulate emissions	
(1985)	-4
(2000)	-19

The USM forecast of price- and income-sensitive demand for the ORBES counties is 525 TWh in 1985 and 1,003 TWh in 2000. The forecasted average yearly growth rate in demand is 3.7 percent between 1976 and 1985 and 4.4 percent between 1985 and 2000. These demand growth rates compared with Scenario 7's 4.0 percent rate over the 1976-2000 period are relatively lower between 1976 and 1985 and relatively higher between 1985 and 2000. The higher growth rate forecast for the later years is probably due to the specification of the constant term in the demand forecasting equation.* It is also due to pre-1980 fuel cost increases and expected SIP compliance, which cause forecasted prices to rise more rapidly before 1985 than after 1985. The post-1985 demand forecasts are inherently less likely to be valid. However, compared with historical data for the ORBES counties, these growth rates represent a significant reduction in the historical annual average demand growth rate. For example, between 1969 and 1977, the average annual growth rate in the ORBES area was 5.1 percent.**

There are several reasons why the forecast does not apply after 1985. First, as is true for all econometrically derived simulation methods, the coefficients used for forecasting have been estimated over a historical period, in this case 1963-1976. Yet we cannot know at this time whether future patterns of electricity demand will be consistent with historical trends as presented in equation (1) of Appendix C. Recent reductions in demand growth suggest that these patterns may already be changing. Second, the specification of equation (1), while straightforward and computationally efficient, may not be appropriate for forecasting electricity demand over an entire 25-year period. More extensive analysis is needed before conclusions can be reached with regard to specification errors. Third, the elasticity estimates used in this forecast are point estimates. It may be more appropriate to use "arc" elasticities, which may reflect more accurately changing conditions in the future. Fourth, the prices used in this forecast were taken from the ORBES area forecast under Scenario 7. Since the forecasting equation's price sensitivity is low, substantially higher prices do not significantly decrease projected demand (see Table 3-30). The sensitivity of the forecasts to alternative trends in real disposable income shows that a rise in real income produces an increased demand for electricity, as expected. However, the income sensitivity is also low. By 2000, a 10 percent decrease in real disposable income results in only a 2 percent reduction in electricity demand. If real income were to increase by 20 percent, electricity demand relative to the baseline would increase by the year 2000 by only 5.5 percent.

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* See Appendix C.

** Taken from Edison Electric Institute data for the East Central Area Reliability Council region.

From this demand forecast, it can be concluded that lower demand growth after 1985 in the ORBES counties will not be driven solely by the price of electricity. Reductions in demand will require changes from the patterns of consumer electricity demand observed in the 1963-1975 period. These changes might encompass changes in insulation levels, more efficient industrial processes, and changes in consumer habits (indeed some of these changes, which are not reflected in this demand forecast, may already be occurring). However, this forecast suggests that, when price and income elasticities are accounted for, electricity demand growth in the ORBES counties could average about 3.7 percent per year before 1985, based on historical consumer response.

Table 3-30

Sensitivity of Demand Forecast to Alternative Electricity Price Trends

(1976 = 1.00)

	1985	2000
Baseline price trend	1.43	2.95
25% real price increase*	1.38	2.77
50% real price increase*	1.34	2.61

* Above the baseline projection using Scenario 7 prices and Witt elasticities with equation (1).

APPENDIX A

USM RESULTS COMPARED WITH HISTORICAL DATA

A.1 Electricity Generation

A.2 Fuel Consumption

A.3 Generating Plant Sites and On-Line Dates

A.4 Emissions

A.5 References

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APPENDIX A

USM RESULTS COMPARED WITH HISTORICAL DATA

In order to ensure the accuracy and reasonableness of the Utility Simulation Model's scenario projections, simulated model results were compared with historical data. Simulation in the USM begins in the year 1976; thus, output for 1976 can be checked and verified against published data to verify the model's outputs. The model also was required to match the scenario specifications of future conditions projected by the ORBES Core Team.

The calibration effort can be categorized into the following areas:

- Electricity generation (present and future)
- Fuel consumption and characteristics
- Generating-plant sites and on-line dates
- Emissions (SO_2, NO_x, and total emitted particulates)

Published data from any one source, of course, are themselves subject to some uncertainty, since comparisons have shown that actual statistics from various sources typically can differ by several percent, despite their historical nature. But when projected capacities, generation, fuel consumption, and emissions are all within several percent of the historical data gathered from various sources, one can have confidence that the simulation procedures are operating correctly. The several sources of historical data used for this comparative analysis include the Edison Electric Institute, the National Coal Association, the Sulfate Regional Experiment, and FPC Form 67 and Form 423.

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A.1 Electricity Generation

Electricity Generation, 1976

The two major sources of electricity in the ORBES counties during 1976 were nuclear and coal-fired units. To validate the model, the USM's total generation figures were compared with the generation data published by Edison Electric Institute (EEI) for each of the six states. Figures A-1 and A-2 compare the USM results with EEI data by state and fuel type. Since generation within a state is the end result of aggregating the USM's projected generation for each unit and for many different owner utilities whose service areas often cross state boundaries, the agreement between the USM results and the EEI data is very good.

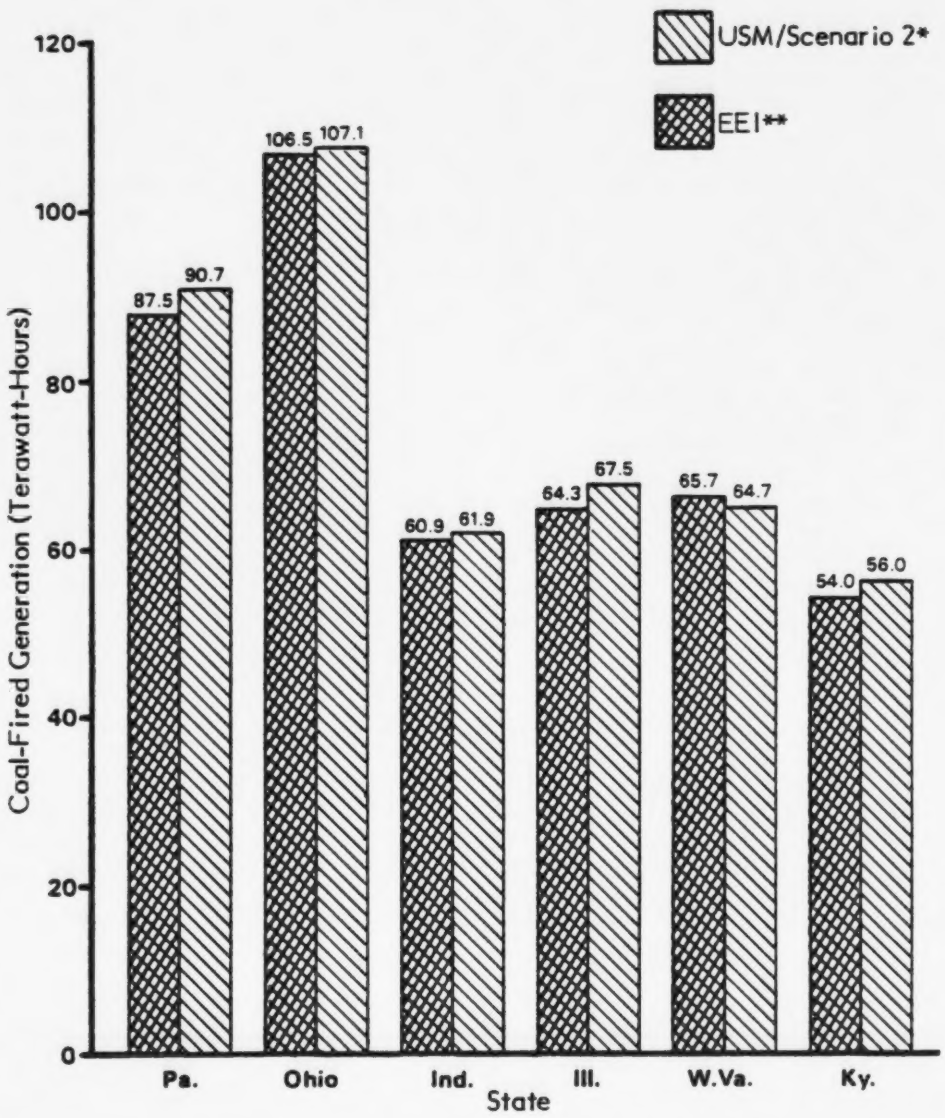
Electricity Generation, 1985 and 2000

The ORBES Core Team specified "target" generation figures for the ORBES counties: each scenario had a target generation figure for 1985 and for 2000 for fossil-fuel-fired plants, nuclear plants, and hydroelectric plants. The 1985 target figure was determined by the ORBES Core Team on the basis of announced utility plans as of 1976. Here it suffices to say that the DEMAND module produces estimates of average and peak demand, by state, from 1976 through the year 2015. The PLANNING module is then run, using these data, to simulate the operation of each "state-firm." The results can be presented by county and state. The "target" generation figures specified by the ORBES Core Team were for ORBES counties located in each state. Many different utility service areas overlapped these ORBES county boundaries.

The results of the calibration for ORBES Scenarios 1, 2, and 4 are presented in Table A-1. As can be seen, on a total generation basis the calibration comes within acceptable bounds (all cases except one are within ± 1.0 percent). However, as the ORBES scenario specification becomes more specific — that is,

Figure A-1

Coal-Fired Electricity Generation in the ORBES States for 1976 (USM Results Compared with EEI Data)

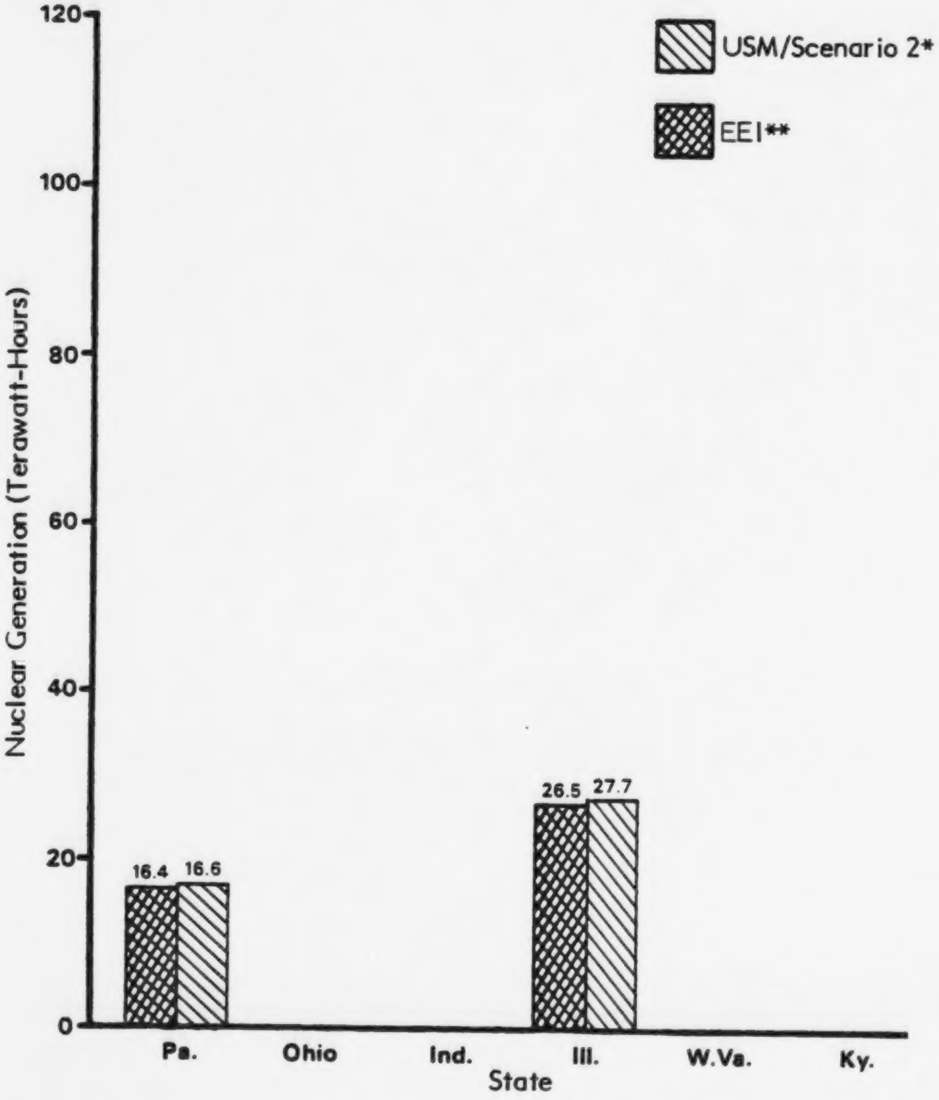


* Teknekron Research, Inc., Utility Simulation Model (Berkeley, Calif., January 1980).

** Edison Electric Institute, Statistical Year Book of Electric Industry (New York, 1977).

Figure A-2

Nuclear Generation in the ORBES States for 1976
(USM Results Compared with EEI Data)



* Teknekron Research, Inc., Utility Simulation Model (Berkeley, Calif., January 1980).

** Edison Electric Institute, Statistical Year Book of Electric Industry (New York, 1977).

Table A-1

USM Calibration — Generation Targets (Terawatt-Hours)

	1985			2000		
	USM	ORBES Target	Difference (%)*	USM	ORBES Target	Difference (%)*
			Scenario 1			
Fossil	477.1	465.0	+2.6	665.4	653.3	+1.9
Nuclear	54.4	61.5	-11.5	62.9	61.5	+2.28
Hydro	4.5	10.3	-56.3	4.6	10.3	-55.3
Total	536.0	536.8	-0.2	732.9	725.3	+1.0
			Scenario 2			
Fossil	481.7	465.0	+3.6	673.0	664.1	+1.3
Nuclear	54.4	61.5	-11.5	62.9	61.5	+2.3
Hydro	4.5	10.3	-56.3	4.6	10.3	-56.3
Total	540.6	536.8	+0.7	740.5	735.9	+0.6
			Scenario 4			
Fossil	392.9	353.1	+11.3	487.8	480.5	+1.5
Nuclear	42.3	61.5	-31.2	62.9	61.5	+2.3
Hydro	4.5	10.3	-56.3	4.9	10.3	-56.3
Total	439.7	424.9	+3.5	555.6	552.3	+0.6

$* \left(\frac{\text{USM}}{\text{ORBES}} - 1\right) * 100.$

as we attempt to calibrate specific types of units to the ORBES input/output (I/O) model specifications — some differences arise.

For example, the USM's projected nuclear fuel generation is 11.5 percent lower than the ORBES target in 1985, and 4.7 percent higher in 2000. The discrepancy in 1985 is explained by a difference in the on-line date for one unit, the 950-MW Clinton #2 Nuclear Station in De Witt County, Illinois. The ORBES Core Team listed this unit's on-line date as 1984 (and, consequently, the unit's expected generation was figured into the ORBES target figure). However, the National Electric Reliability Council (specifically, ECAR) more recently listed the on-line date as 1988.[1] While the Teknekron data base of announced units, TEKUTIL, was modified to be similar to the ORBES Core Team list of steam units built,[2] in cases of discrepancy such as this, the more recent NERC reference was used. Consequently, the variation between the USM and ORBES nuclear generation figures for 1985 rests on this difference. The difference of 4.7 percent in nuclear generation in the year 2000 is explained by the fact that the ORBES I/O model used "nameplate capacity," whereas the USM uses "net capability."

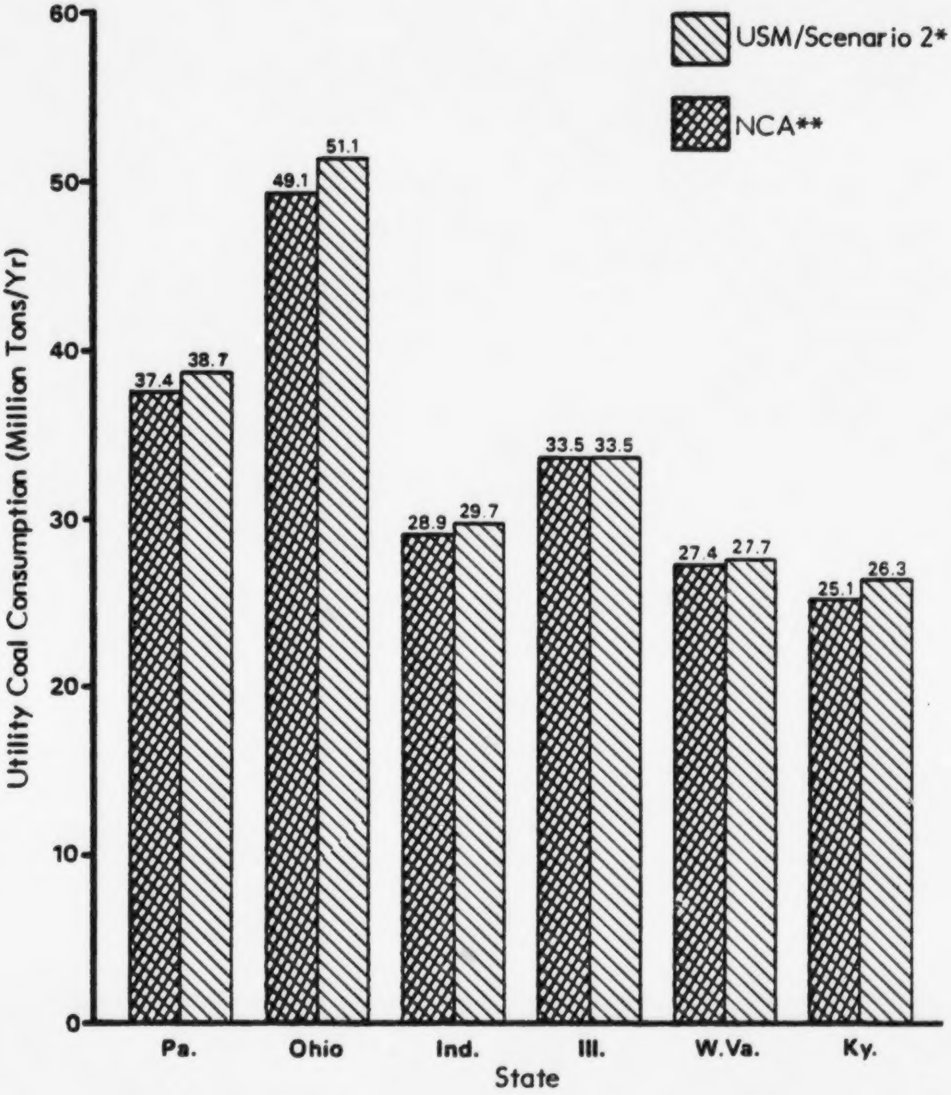
The difference between the USM and ORBES I/O model estimates for hydroelectric generation is explained by the presence of four planned 250-MW pumped hydro units (the Davis Hydroelectric Facility) in Tucker County, West Virginia, and by the nature of the USM dispatch algorithm. Dispatch in the USM is accomplished through a two-stage process: the power to pump and the power generated from these peaking units are calculated in stage one; then the resulting load curve is recalculated and reported in stage two. For the ORBES region, the USM projects hydro utilization as indicated in the table.

A.2 Fuel Consumption

Another indicator of the USM's validity is its ability to reproduce, through simulation, actual utility fuel consumption. Figure A-3 summarizes the comparisons for coal, using 1976 historical data published by the National Coal Association (NCA).

Figure A-3

Utility Coal Consumption in the ORBES States for 1976
(USM Results Compared with NCA Data)



* Teknekron Research, Inc., Utility Simulation Model (Berkeley, Calif., January 1980).

** National Coal Association, Steam Electric Plant Factors (New York, 1977).

A.3 Generating-Plant Sites and On-Line Dates

Generating-unit data regarding planned sites and nominal on-line dates were provided by the ORBES Core Team.[2] The ORBES list of unit additions from 1976 to 1985 was based on announced plans, while their 1985-2000 additions were added linearly to obtain generation levels projected for the year 2000 by the ORBES I/O model. The generating system growth projected by the USM was not linear over time; rather, it generally reflected the annual growth rates projected by ECAR, scaled to the ORBES scenario specifications for 1985 and 2000. The utility ownership patterns used in the USM were specified to match the sites and unit specifications provided by the ORBES Core Team. Figures 2-1, 2-2, and 2-3 (in the main text of this report) illustrate differences in the siting patterns across ORBES scenarios as determined by the Core Team.

A.4 Emissions

The USM emission estimates for Scenario 2 were compared with SURE data for each ORBES county in 1976. (SURE, the Sulfate Regional Experiment, monitored emissions from individual generating units.) Table A-2 summarizes the 1976 correlation by summing the county-based SO_2 emissions by state for both the USM projected emissions and the SURE emissions inventory.

The agreement on SO_2 emissions is fairly good, within ± 8 percent, for three states (Pennsylvania, Ohio, and Kentucky); and it is even better, within ±3 percent, for the three remaining states (Indiana, Illinois, and West Virginia).

The USM results were also compared with data from other sources. Table A-3 presents a state-by-state comparison of the USM Scenario 2 results for 1976 and the FPC Form 67 data for 1975 (the most recent Form 67 data available). We expected that the USM 1976 SO_2 values would be higher, on the average, than the 1975 data, which was the case.

Table A-2

ORBES County SO_2 Emissions (Millions of Tons/Year) Summed by State, 1976 (USM Scenario 2 Results Compared with SURE Data)

	ΣUSM*	ΣSURE**	Difference (%)***
Pennsylvania	1.14	1.07	+6.5
Ohio	2.39	2.62	-8.8
Indiana	1.37	1.41	-2.8
Illinois	1.33	1.34	-0.7
West Virginia	1.05	1.06	-0.9
Kentucky	1.68	1.59	+5.7
TOTAL ORBES COUNTIES	8.96	9.09	-1.43

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* Teknekron Research, Inc., Utility Simulation Model (Berkeley, Calif., January 1980).

** T.F. Lavery et al., "Formation and Regional Accumulation of Sulfate Concentrations in the Northeastern United States," Proceedings of the Symposium on Environmental and Climatic Impact of Coal Utilization (New York: Academic Press, forthcoming).

*** Difference $= \left(\frac{\Sigma \text{USM}}{\Sigma \text{SURE}}\right) - 1 * 100.$

Table A-3

ORBES State SO_2 Emissions (Millions of Tons/Year), 1975-1976 (USM Scenario 2 Results for 1976 Compared with FPC Form 67 Data for 1975)

	ΣUSM*	ΣFPC**	Difference (%)***
Pennsylvania	1.80	1.520	+18.4
Ohio	2.94	2.688	+9.4
Indiana	1.67	1.623	+2.9
Illinois	1.97	1.581	+24.6
West Virginia	1.05	1.079	-2.7
Kentucky	1.47	1.399	+5.1
TOTAL ORBES STATES	11.10	9.900	+10.2

* USM Scenario 2, for the year ending December 31, 1976.

** FPC Form 67 data, for the year ending December 31, 1975.

*** Difference $= \left(\frac{\Sigma USM}{\Sigma FPC} - 1 \right) * 100.$

A.5 References in Appendix A

1. ECAR Information Report on Coordinated Regional Bulk Power Supply Programs, 1 April 1979.

2. Gary L. Fowler, University of Illinois at Chicago Circle; Robert E. Bailey, the Ohio State University; J.C. Randolph, Indiana University; and Steven I. Gordon, the Ohio State University, The Ohio River Basin Energy Facility Siting Model: List of Sites and On-Line Dates for ORBES Scenarios, Ohio River Basin Energy Study, Phase II, vol. II, Grant Nos. EPA R805588, R805589, and R805609 (forthcoming).

APPENDIX B

IMPLICATIONS OF EMISSION STANDARDS FOR UTILITY COAL AND POLLUTION CONTROL CHOICES

B.1 Emission Standards for Coal-Fired Power Plants in the ORBES Counties

B.2 Coal Sulfur Variability

B.3 Coal and Pollution Control Trade-offs

B.4 Coals Selected for USM Scenarios

B.5 References

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APPENDIX B

IMPLICATIONS OF EMISSION STANDARDS FOR UTILITY COAL AND POLLUTION CONTROL CHOICES

B.1 Emission Standards for Coal-Fired Power Plants in the ORBES Counties

Emissions from coal-fired power plants are controlled by either State Implementation Plans (SIPs), New Source Performance Standards (NSPS), or revised New Source Performance Standards (RNSPS). Plants that came on line before 1977 are controlled by the SIPs; and we have assumed that there are two standards within the SIP for each state — one (more stringent) for urban units, and the other (less stringent) for rural units. Hence, we have assumed 12 expected SIPs within the ORBES area. Plants coming on line between 1977 and 1983 are controlled by the NSPS, unless the applicable SIP is more stringent, in which case the SIP controls (which occurs in the urban counties of Pennsylvania). Finally, plants coming on line in 1983 and later (legally defined as beginning construction after September 1978) are controlled by the RNSPS.

The average SIP, NSPS, and RNSPS emission limits for SO_2, particulates, and NO_x for each ORBES state are shown in Tables B-1, B-2, and B-3. Appendix G briefly discusses the importance of SIP averaging times and the implications of the latest unit-specific SIP SO_2 information.

In general, a utility will select that coal or coal blend which, when burned with the required pollution controls, allows the utility to operate at least cost. In some cases, however, the utility's coal choices may be limited by certain constraints, including coal production constraints, transportation constraints, and so forth. Furthermore, pollution control regulations for new plants will make it necessary for the utility to examine such factors as coal sulfur variability, the cost of flue gas desulfurization, and the costs of various generating technologies. The following discussions address some of these factors.

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Table B-1

SO_2 Emission Limits ($lb/10^6$ Btu) for Coal-Fired Plants in the ORBES States

State	SIP Urban	SIP Rural	NSPS	RNSPS*
Pennsylvania	0.60	1.80	1.20	0.41
Ohio	1.40	4.50	1.20	0.41
Indiana	1.21	5.00	1.20	0.55
Illinois	1.80	6.00	1.20	0.55
West Virginia	1.60	3.20	1.20	0.45
Kentucky	1.21	5.70	1.20	0.45

* Where potential emissions are greater than 0.60 lb $SO_2/10^6$ Btu, the RNSPS require a 90 percent reduction of potential emissions and limit maximum allowable emissions to 1.20 lb $SO_2/10^6$ Btu. Where potential emissions are less than 0.60 lb $SO_2/10^6$ Btu, a minimum removal of 70 percent of the potential SO_2 emission is required. The emission rates listed above for the RNSPS plants reflect the characteristics of the coals used in the ORBES scenarios (see Section B.4 of this appendix).

Table B-2

Particulate Emission Limits ($lb/10^6$ Btu) for Coal-Fired Plants in the ORBES States

State	SIP Urban	SIP Rural	NSPS	RNSPS
Pennsylvania	0.10	0.10	0.10	0.03
Ohio	0.10	0.10	0.10	0.03
Indiana	0.10	0.10	0.10	0.03
Illinois	0.10	0.10	0.10	0.03
West Virginia	0.05	0.05	0.10	0.03
Kentucky	0.20	0.20	0.10	0.03

Table B-3

NO_x Emission Limits (lb/10^6 Btu) for Coal-Fired Plants in the ORBES States

State	SIP Urban	SIP Rural	NSPS	RNSPS
Pennsylvania	–	–	0.7	0.6
Ohio	–	–	0.7	0.6
Indiana	–	–	0.7	0.6
Illinois	0.75	–	0.7	0.6
West Virginia	–	–	0.7	0.6
Kentucky	–	–	0.7	0.6

B.2 Coal Sulfur Variability*

Because of restrictions on SO_2 emissions, specifications regarding the allowable sulfur content of delivered coal will become more specific, and the penalties imposed upon coal suppliers who do not conform to them will become stiffer. These unit-specific coal-sulfur specifications will reflect each generating unit's required SO_2 removal (and, in some cases, precombustion SO_2 removal), the fuel-averaging period implied in the standard (which relates directly to coal-lot size), an allowable rate of exceedances (if any), and an acceptable level of confidence in predicting compliance with the standard. Here we discuss these considerations and the factors that will influence coal and pollution control selection by utilities and industry.

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* This discussion is adapted from a Teknekron Research report prepared by Gladys Sessler (see reference 1).

To meet their obligations, coal producers will have to monitor their products periodically, using EPA-approved methods of sampling and measurement, and they may find it necessary to adjust the mix of coals they supply during a certain period. First, however, they will have to conduct a judicious sampling of their in-situ resources in order to estimate the values and variability of coal sulfur (weight of sulfur per thermal content of coal) in appropriate lot sizes of the coal they can reliably produce during a certain time span. Petrological and geostatistical techniques may establish a theoretical maximum number of required core drillings and improve the confidence of the estimates made from analyzing core samples.

In general, the sampling and analysis of mine cores and the sampling and analysis of the mined (and possibly cleaned) coal will constitute different activities, and the results obtained will be used in different, though related, ways. The core data may be used to focus upon those areas of the coal field that can produce a product meeting particular delivered-coal specifications. In general, however, these data cannot be used to predict reliably the distributional form and the mean and variance of the as-mined or cleaned coal.

Future developments resulting from ongoing geological research by the U.S. Geological Survey and some of the larger coal companies may lead to (1) a better understanding of the origin and history of existing coal fields and, in turn, of the chemical characteristics of these fields, and (2) a better grasp of the relationship between the crystalline structure of coals and their chemical constituents. Results from these studies along with more careful mapping of the stratigraphic layers within a seam may improve the predictive value of core-sample data by producing reliable isopachs and sulfur isopleths of the coal within a given field. Such research, however, is still in the preliminary stage and cannot yet be applied in coal mining operations. Geostatistical methods, using tools from the coal-geology studies, are also expected to enhance the predictive value of core sampling. While still largely in the developmental stages, such methods — adapted from programs developed for uranium mining — are now being tested by the Pennsylvania Electric Company (Penelec) at its coal field in Homer City, Pennsylvania, in order to determine the contours of the sulfur isopleths within the field (using a minimum number of drillings), so as to mine selectively SO_2 compliance coal for Penelec's NSPS power plant at Homer City.[2]

If the core samples from a coal field suggest that certain areas of the field do contain coal capable of meeting a certain user's sulfur specifications (accounting for sulfur reduction by coal cleaning if necessary), and if the coal producer wishes to supply coal from these areas to the user, then the producer must analyze samples of specified lot sizes of the coal to be shipped (raw or cleaned). Through such analysis he will be able to determine the distributional form of the sulfur content within these lot sizes and the values of such relevant statistics as expected value, variance, and relative standard deviation (RSD).*

To illustrate how SO_2 standards will govern sulfur-content specifications, we shall refer to two examples. First, the revised 1979 New Source Performance Standards (which apply to power plants beginning construction after September 1978) require a 70 to 90 percent reduction of SO_2 emissions throughout the fuel cycle (depending upon the weight of sulfur per thermal content of the coal); furthermore, they stipulate a ceiling of 1.2 lb SO_2 per million Btu.

> Compliance with the emission limit and percent reduction requirement is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.[3]

Second, the Ohio SIP for SO_2 (effective October 1979) specifies different SO_2 ceilings for different plant units and in all cases requires a 24-hour period of fuel averaging (generally permissible in Ohio as a measure of a plant's SO_2 emissions). Two 24-hour exceedances are allowed during each 30-day period (with each day completing a new 30-day period).[4] Since emission standards for SO_2 are most frequently specified in terms of the weight of SO_2 emitted per unit of heat content of coal (i.e., lb SO_2 per million Btu), "coal-sulfur content" in the following discussion will mean the weight of coal sulfur per unit of heat content

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* RSD equals the ratio of the standard deviation to the mean. It is sometimes called the coefficient of variation.

(i.e., lb S per million Btu). If it is assumed that no SO_2 is retained in the coal ash, then the weight of SO_2 emissions will be twice that of the as-burned sulfur.

If the coal is cleaned, and if the SO_2 standard requires a certain percentage reduction of SO_2 emissions and gives credit for this reduction at any stage of the fuel cycle (as is the case with the RNSPS), then an additional coal-monitoring activity will be needed. Currently, sulfur content is not measured on a regular basis prior to coal cleaning; only the cleaned coal — that is, the coal shipped to the customer — is directly of interest to the supplier and is therefore subjected to periodic sulfur analysis. But under the RNSPS, the baseline value of sulfur content will also have to be measured in order to credit sulfur reduction from coal cleaning.

Note, however, that the RNSPS specify different averaging periods for measuring sulfur content at different stages of the fuel cycle: SO_2 emissions from a power plant must be monitored continuously to obtain a 30-day rolling average (as noted above); but, to obtain credit for sulfur-content reductions from coal cleaning, "a coal lot size equaling the 90-day quarterly fuel quantity for a specific power plant may be used if representative sampling can be conducted for the raw coal and product coal."[5]

In all cases, both the expected values and variability of the sulfur content of the shipments of coal (which may or may not be cleaned) must be determined in order to establish a margin of error for meeting sulfur specifications. That is, the supplier must determine the expected value of the sulfur content and the allowable ceiling for an appropriate lot size of a given coal to within a certain level of confidence. The appropriate lot size will correspond to: (1) the required averaging period for sampling either the coal or the SO_2 emissions; and (2) the plant's typical rate of coal input. For example, a 500-MW plant operating at full capacity may require about 5,000 tons of coal per day, so that, if the required averaging period is 24 hours (as it is in the Ohio SIP), the appropriate quantity of coal for each sample (lot size) will be about 5,000 tons.

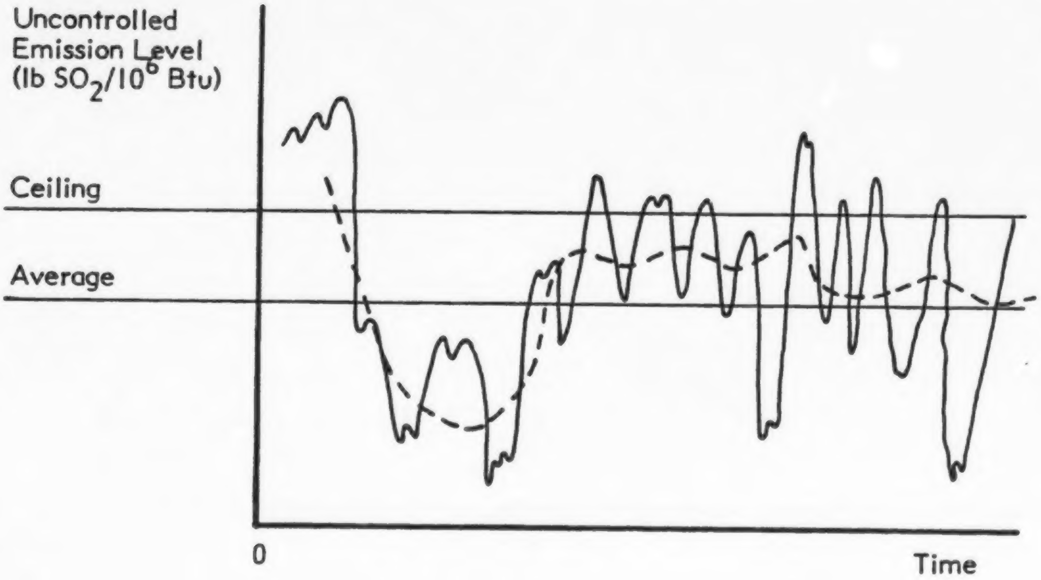
The expected value of the sulfur content will relate directly to the expected SO_2 emission level; and, because of statistical fluctuations, the effective SO_2 emission limit will be the expected value of SO_2 emissions, a value lower than the maximum allowable SO_2 emissions. How much lower will depend upon such factors as: the relative standard deviation (RSD) of SO_2 emissions; the allowable frequency with which the maximum SO_2 emission level can be exceeded; the allowable "confidence level," reflecting an acceptable (small) probability of violating the standard; and the probability distribution (for example, a normal or lognormal distribution) of measured SO_2 emission levels.

A larger RSD means a larger difference between the allowable maximum and mean SO_2 emissions and hence a lower (more stringent) effective SO_2 emission limit. One of the factors that increases the RSD of the weight percentage of sulfur in a particular coal is a decrease of the lot size of the coal from which measured samples are drawn, since fluctuations are expected to be smoothed with larger lot sizes. Since, for a power plant burning coal at a fixed rate, the lot size to be sampled is related directly to the averaging period, the variance and RSD also decrease with increased averaging periods. The effect of smoothing fluctuations with larger lot sizes (or averaging periods) is illustrated schematically in Figure B-1, in which the same coal is sampled at two different intervals. Compared with the solid — and more fluctuating — curve, the dotted (less varying) curve represents sampling at less frequent intervals (that is, larger averaging periods or larger lot sizes). If Ohio power plants were permitted to determine SO_2 emissions on the basis of 30-day composite samples — rather than 24-hour composite samples — the RSD would theoretically be expected to equal the 24-hour RSD divided by $\sqrt{30}$.

We observe that the decrease of RSD with increasing lot size implies that the SO_2 limit, for a given averaging period, is effectively more stringent for smaller boilers than for larger boilers. As the sizes of the boilers decrease, so that they approach the range of most industrial boilers, the inverse relationship of RSD and lot size cannot be expected to hold. Indeed, because various interacting fluctuations become relatively more important at smaller lot sizes, the measurement — and therefore the concept — of variability becomes inappropriate for very small boilers.

Figure B-1

Illustration of the Effect of Averaging Period on RSD



The following point must be emphasized: the assumption that RSD is a predictable (decreasing) function of lot size for large lot sizes implies that, for a given large lot size, the RSD is the same for every lot. It must also be emphasized that this assumption posits that all lots contain identical coals. Such uniformity of coal, of course, never actually exists. Rather, RSDs of sulfur content (again, we mean lb S per million Btu) vary from coal to coal for a given lot size. It is not surprising, then, that recent observations of lot size versus RSD have not consistently shown an inverse relationship between lot size and RSD.[6,9] Where the coal samples (and RSDs) are reasonably similar from lot to lot (and effective geostatistical sampling techniques as well as coal cleaning may help increase the similarities among samples of a given lot size), a greater lot size can be expected to have a smaller RSD. The assumption (sometimes made for lack of empirical data) that the RSD per unit weight of a coal is independent of the coal's sulfur content implies a smaller variance and standard deviation for lower-sulfur coals (since the RSD equals the ratio of the standard deviation to the mean).

The RSD of the SO_2 emissions (in pounds per million Btu) will be determined largely by the RSD of the sulfur content, but not entirely. The variability in a coal's heating value affects the RSD of the SO_2 emissions (lb/10^6 Btu) to a small extent; a report on sulfur variability by PEDCo sets the RSDs of SO_2 emissions (lb/10^6 Btu) equal to 1.05 times the RSDs of sulfur content.[6] In addition, three other factors affect the RSD of sulfur emissions: (1) the variability of sulfur retention in the ash during combustion (the fraction of sulfur retained depends largely upon the coal's alkaline content); (2) the variability of the small amount of sulfur removal during pulverizing of the coal at the power plant; and (3) the performance of pollution control devices for SO_2 removal.

An important factor in determining the applicable effective SO_2 emission level is the acceptable confidence level, related to the probability of emissions being above the established maximum SO_2 emission level. The greater the level of confidence that no exceedances (or an allowable number of exceedances) will occur in a specified time, the greater will be the difference between the allowable maximum and mean SO_2 emission levels. Thus, the effective SO_2 limit will be more stringent for a greater confidence level. A confidence level of 95 percent, for example, implies that, for a normal probability distribution (see below), the probability of exceeding the maximum allowable SO_2 emission level is 0.05, or that violations will be tolerated about 18 days per year. A confidence level of 99.87 percent implies that violations will be tolerated about one day in a thousand.

The probability distribution of sulfur measurements also affects the allowable effective level of SO_2 emissions, given a maximum SO_2 emission level and a value of RSD. For convenience, a normal distribution of sulfur content is often assumed. But, in fact, using a distribution skewed toward higher values — for example, a lognormal or inverted gamma distribution — has provided a good empirical fit to a number of sets of coal-sulfur measurements. A lognormal distribution can be transformed into a normal distribution by setting the mean equal to the natural logarithm of sulfur content in the lognormal distribution and setting the standard deviation equal to the RSD of the lognormal distribution. For a given RSD and confidence level, a coal will have a lower mean sulfur level if its sulfur content is lognormally distributed than if it is normally distributed.

Given a confidence level for a normal distribution, the difference between the mean and the maximum SO_2 emission limit can be expressed as a specified multiple of the standard deviation. This multiple is called the normal variate and can be found in standard tables of "normal curve areas." Here are some examples of normal variates, their corresponding confidence levels, and their implications regarding the number of days per year in which the maximum SO_2 emission limit can be violated.

Confidence Level (%)	Z = Normal Variate (Number of Standard Deviations between the Mean and Upper Limit)	Number of Days per Year of Tolerated Violations
84.13	1.0	58
95.00	1.645	18
97.72	2.0	8
99.87	3.0	<1

The mean value, m, of a normal distribution is related to the emission limit, max, by

$$\text{max}-m = Z \cdot \sigma,$$

or, since $RSD = \sigma/m$, by

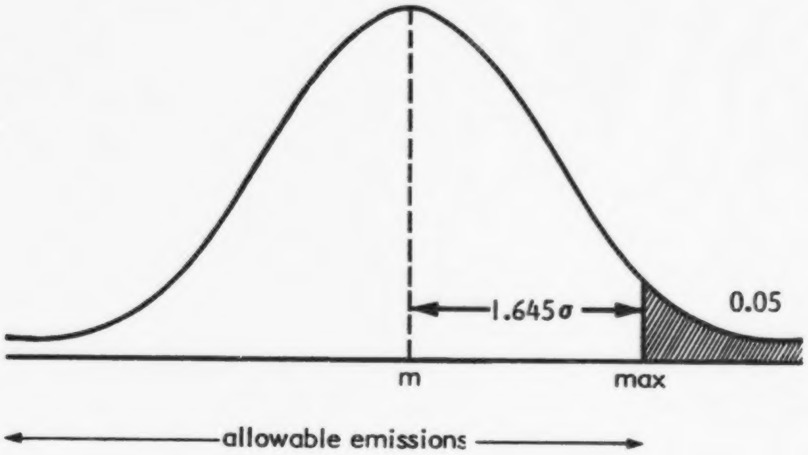
$$m = \text{max}/(1 + Z \cdot RSD),$$

where σ is the standard deviation and Z is the normal variate, corresponding to a given confidence level.

Diagramatically this relationship is illustrated for a confidence level of 95 percent in Figure B-2:

Figure B-2

A Probability Distribution



It is expected that a confidence level of 99.87 percent (calling for three standard deviations between the mean and the maximum) will be required by EPA.[7]

An analysis of a limited number of data sets has shown that the RSD of pounds of SO_2 emitted per million Btu decreases as a result of physical coal cleaning (PCC), somewhat more so with somewhat deeper levels of cleaning,[8] but that the RSD of the weight percentage of sulfur in the coal often does not decrease after PCC. These results indicate the importance of the enhancement of the cleaned coal's heating value. They also suggest that – in the raw coal – the RSD of pounds of SO_2 emitted per million Btu is greater for the pyritic SO_2, which may be partially removed by PCC, than for the organic SO_2, which is not removed by PCC.

Since organic sulfur is bound to the coal and not generally removed by PCC, while the pyritic sulfur is associated with the incombustible (ash-producing) material and is removed by PCC, a lower value of the RSD of lb $SO_2/10^6$ Btu suggests that, in a raw coal, the values of RSDs (lb SO_2 per million Btu) are higher for pyritic sulfur than for organic sulfur. While reported coal sulfur values are not generally separated into pyritic and nonpyritic sulfur, the washability data prepared by the Bureau of Mines[10] do include mean values and standard deviations of measurements of both pyritic and total sulfur for raw and cleaned coals within a county and coal bed. In examining these data to compare the RSDs of pyritic and organic sulfur (lb $SO_2/10^6$ Btu), we found that, indeed, the raw-coal RSDs were usually higher for pyritic sulfur than for total sulfur. Further, as can be seen in Table B-4, when these data are aggregated on a regional basis, the raw-coal RSDs for pyritic sulfur are consistently higher than those for total sulfur.

We will illustrate how the factors mentioned above can determine the effective SO_2 emission level required. Before doing so, however, we discuss Table B-5, which presents values of sulfur variability as RSD, computed from measurements of sulfur content and heating value in samples of coal from Ohio. The data represent various lot sizes of coal from various counties and coal seams. The table also indicates the number of samples available in each data set, the type of mining (surface or underground), average values of potential SO_2 emissions, and whether the data set represents raw or washed coal (only one of the coals listed is washed). We note that, in general, the data set for a given coal and lot size can represent either a composite sample of that lot size or the average of individual measurements made on different samples of the same lot size.

Among the 39 Ohio samples listed in Table B-5, the range of RSD values is large: from 8.82 to 26.60 percent. There is no correlation among RSD values in these data for samples taken from the same county, seam, and type of mine.

In Table B-6, we present computed values of the required average SO_2 emissions from coal to be burned at two generating units whose maximum allowable SO_2 emissions under the SIP are, respectively, 1.61 and 4.46 pounds per million Btu. We have used alternative assumptions regarding the value of the RSD, the confidence level, and the type of probability distribution of sulfur content. Two values of RSD are compared — 0.15, sometimes assumed for raw coal fed daily

Table B-4

Total Sulfur and Pyritic Sulfur Content: Comparison of Variability

Coal Region	Number of Samples	Sulfur Content of Raw Coal					
		Pyritic Sulfur (%)			Total Sulfur (%)		
		Mean %	Sigma	RSD	Mean %	Sigma	RSD
N. Appalachia	227	2.01	1.3	0.65	3.01	1.6	0.53
S. Appalachia	35	0.37	0.4	1.08	1.04	0.6	0.58
Alabama	10	0.69	0.8	1.16	1.33	0.9	0.68
Eastern Midwest	95	2.29	1.0	0.44	3.92	1.2	0.31
West Midwest	44	3.58	1.9	0.53	5.25	2.3	0.44
Western	44	0.23	0.3	1.3	0.68	0.3	0.44

Source: Joseph A. Cavallero et al., Sulfur Reduction Potential of the Coals of the United States, RI 8118 (Pittsburgh, Pa.: U.S. Department of the Interior, Bureau of Mines, 1976).

Note: RSD is the ratio of the standard deviation (sigma) to the mean.

Table B-5

Values of the Relative Standard Deviation (RSD) of Sulfur Content in Ohio Coals

County	Seam Name	Mining Method	Preparation Method	Tons	Average SO_2 Emissions ($lb/10^6$ Btu)*	RSD (%)	Number of Samples
Tuscarawas	L. Kittanning M. Kittanning	Surface	Raw	1,150	7.50	19.47	68
	L. Kittanning	Surface	Raw	1,426	7.26	21.19	362
	L. Kittanning	Surface	Raw	1,213	6.37	16.65	337
	No. 7 & 7A	Surface	Raw	1,248	6.66	20.62	175
	M. Kittanning	Surface	Raw	1,190	6.59	22.26	45
	Unknown	Surface	Raw	–	–	–	–
Jefferson	Pittsburgh	Surface	Raw	1,495	6.00	22.13	116
Harrison	L. Freeport	Underground	Raw	–	–	–	275
	Unknown	Surface	Raw	1,311	6.11	19.64	232
Coshocton	No. 6	Surface	Raw	3,361	8.26	21.71	454
	No. 6	Underground	Raw	2,373	8.72	19.15	455
	No. 6	Underground	Raw	947	9.48	18.86	203
	Waynesburg	Surface	Raw	1,294	6.75	15.82	531
	No. 5	Surface	Raw	1,388	7.15	16.99	262
	No. 5	Surface	Raw	1,044	7.02	23.39	108
	Unknown	Surface	Raw	959	7.13	24.51	33
	Unknown	Surface	Raw	1,181	7.12	14.77	40
	No. 6	Surface	Raw	1,250	8.09	22.56	43
	Unknown	Surface	Raw	1,449	6.84	7.34	8
	L. Kittanning M. Kittanning	Underground/ Surface	Raw	1,016	5.71	3.15	3
Muskingum	Unknown	Surface	Raw	1,183	6.98	31.33	131
	No. 8	Surface	Raw	1,192	6.68	17.05	103
	M. Kittanning	Surface	Raw	1,568	6.16	21.07	479
	Unknown	Surface	Raw	1,245	6.62	15.09	51
	M. Kittanning	Surface	Raw	924	6.05	8.82	6
Perry	M. Kittanning	Surface	Raw	1,192	6.50	22.34	295
	Unknown	Surface	Raw	1,360	7.49	16.51	11
	No. 6	Underground	Washed	992	4.54	12.07	262
	Unknown	Surface	Raw	1,046	5.84	21.04	53
	Unknown	Surface	Raw	2,025	1.51	–	3
	Unknown	Surface	Raw	512	6.25	14.72	3
Vinton	Clarion	Surface	Raw	989	7.22	15.35	210
	Unknown	Surface	Raw	984	6.77	18.85	251
	Unknown	Surface	Raw	960	6.52	24.66	176
	Clarion L. Kittanning	Surface	Raw	849	6.71	26.60	78
	Unknown	Surface	Raw	1,040	5.65	–	2

Source: Written Communication from Ray Morrison, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Durham, North Carolina, April 14, 1979.

* Assuming that all sulfur leaves the stack as SO_2.

Table B-6

Expected Average SO_2 Emissions from Two Generating Units under Different Assumptions about Sulfur Variability[*]

Hypothetical Maximum Allowable Emission (lb $SO_2/10^6$ Btu)	RSD	Confidence Level[**] (%)	Mean Emission (lb $SO_2/10^6$ Btu) Assuming Normal Distribution[+]	Median Emission (lb $SO_2/10^6$ Btu Assuming Lognormal Distribution[++]
1.61	.15	99.87	1.10	1.02
1.61	.08	99.87	1.29	1.26
1.61	.15	95.0	1.28	1.25
1.61	.08	95.0	1.42	1.38
4.46	.15	99.87	3.07	2.84
4.46	.08	99.87	3.59	3.49
4.46	.15	95.0	3.58	3.42
4.46	.08	95.0	3.94	3.89

[*] For a given maximum SO_2 emission level, the allowed mean value for a sample of compliance coal will be determined by the RSD (relative standard deviation = standard deviation/mean), the probability distribution of the sampled value, and the required confidence level. The RSDs of .15 and .08 have been assumed to apply to raw and cleaned coals in quantities required daily by a large power plant. No exceedances per month are assumed beyond those implied by the confidence level.

[**] A 95 percent confidence level implies that emissions will exceed the emission limit 5 percent of the time, or one day in twenty. A 99.87 percent confidence level implies that emissions will exceed the emission limit 0.13 percent of the time, or less than one day per year.

[+] Assuming a normal probability distribution, the mean, m (equal to the median in a normal distribution), is found by

$$m = \frac{\text{max}}{1 + z \ \text{RSD}},$$

where:

z = 3 standard deviations above the mean for a 99.87 percent confidence level, and

z = 1.645 standard deviations above the mean for a 95 percent confidence level; and

max = maximum allowable emission (1.61 and 4.46 lb $SO_2/10^6$ Btu, respectively, for the two generating units).

[++] Assuming a lognormal distribution, the median, m, is found by:

$$\ln m = \ln \text{max} - z \cdot \text{RSD}, \text{ or}$$

$$m = \text{max} \ e^{-z \cdot \text{RSD}}$$

(see preceding note for symbols)

to large power plants, and 0.08, an assumed RSD for the corresponding cleaned coal. Two confidence levels are used: 99.87 percent, corresponding to three standard deviations above the mean; and 95 percent, corresponding to 1.645 standard deviations above the mean. Finally, two distributions are considered: a normal distribution and a lognormal distribution.

To the extent that a plant can burn coal with a higher average sulfur content, its fuel options will include a greater number of lower-priced coals. How much of a difference do the alternative sets of assumptions in Table B-6 make for the allowable mean value of SO_2 emissions (in lb SO_2 per million Btu)? From the table we see that, for a limit of 1.61 lb and a normal probability distribution, the mean SO_2 emissions at the 99.87 percent confidence level with an RSD of 0.15 must be 1.10 lb; with the lower RSD of 0.08, the mean can be higher – 1.29 lb (or 17 percent higher). At the 95 percent confidence level, the highest allowable mean SO_2 emission level corresponding to the RSD of 0.15 is 1.28 lb; and here, again, the allowable mean SO_2 value is higher with the lower RSD of 0.08 – 1.42 lb (or 11 percent higher). Looking at a limit of 4.46 lb, the expected average SO_2 emissions are 17 percent higher at the higher confidence level (3.58 lb instead of 3.07 lb) and 11 percent higher at the lower confidence level (3.89 lb instead of 3.49 lb).

Table B-6 also illustrates that, for an assumed value of RSD, the mean sulfur level to achieve compliance will be lower with a lognormal distribution than a normal distribution of measured sulfur values.

If one or more exceedances per month are permitted (with the specified level of confidence), a higher (more easily attainable) mean SO_2 value will be acceptable. Thus, we have also computed the average sulfur level assuming that two exceedances per month are allowed for one of the cases described in Table B-6: RSD of 0.15, SO_2 standard of 4.46 lb SO_2 per million Btu, confidence level of 99.87 percent, and a normal probability distribution.

The mean, m, for this case when no exceedances are allowed was shown to be 3.07, using

$$4.46 \text{ lb} - m = 3m \cdot 0.15,$$

where 0.15 is the RSD and the factor 3 is the normal variate (the number of standard deviations above the mean) corresponding to a 99.87 percent confidence level (a probability of .0013 that the 24-hour standard of 4.46 lb SO_2 per million Btu will be exceeded).

To find the average SO_2 level when two exceedances per month are permitted, we first compute the single-day probability, P, of meeting the requirement that the probability of three or more violations occurring during a 30-day period is .0013 (corresponding to a 99.87 percent confidence level). To do so, we sum the probabilities of (1) no violations, (2) one violation, and (3) two violations:

$$.0013 = 1 - \binom{30}{0} P^0 (1 - P)^{30} + \binom{30}{1} P^1 (1 - P)^{29} + \binom{30}{2} P^2 (1 - P)^{28},$$

or

$$.9987 = (1 - P)^{30} + 30^P (1 - P)^{29} + 435 P^2 (1 - P)^{28}.$$

Through iteration, the value of P is found to be about 0.013. We now apply the normal variate corresponding to P = 0.013, which is 2.23 (for the same case, but with no exceptions, the normal variate is 3.0, corresponding simply to 0.0013 or a 99.87 percent confidence level). Therefore, for the SIP limit of 4.46 lb SO_2 per million Btu and an RSD of 0.15, allowing two exceptions per month implies:

$$4.46 \text{ lb} - m = 0.15m \cdot 2.23,$$

or

$$m = 3.34 \text{ lb } SO_2 \text{ per million Btu},$$

which can be compared with the lower allowable mean of 3.07 lb SO_2 per million Btu when no exceedances are permitted for the 24-hour standard of 4.46 lb SO_2 per million Btu, given the same confidence level (99.87 percent).

The result yielded by a similar computation for three exceptions per month was not very different: 3.36 instead of 3.34 lb SO_2 per million Btu.*

B.3 Coal and Pollution Control Trade-offs

For each power plant or industrial facility there is an associated fuel-cycle cost for any coal that might be burned. Less expensive coals may have higher sulfur contents and hence require a higher degree of pollution control to meet a specified emission standard. Low-sulfur coals will probably command premium prices but require a lower degree of SO_2 pollution control. This cost trade-off must be considered in selecting pollution control devices (scrubbers, electrostatic precipitators, etc.), whether for installation at a new plant or for retrofitting at an older one, and in selecting the appropriate coals for various sizes of coal-fired boilers. If the coals currently delivered do not meet the applicable emission standard, compliance with that standard will demand either changing coals or retrofitting pollution control equipment. The decision to change coals, for example, may involve switching to a low-sulfur coal from more distant mines or to a cleaned coal from Appalachia. The choice will depend largely on the degree of SO_2 emission control required.

In order to select representative complying coals for the ORBES scenarios examined in the USM, the total fuel-cycle costs of delivering and using various coals at selected sites were estimated. For each ORBES state in turn, the costs of using local run-of-mine coal, cleaned coals, and low-sulfur western coals were analyzed from the perspective of a hypothetical utility fuel manager.** The following general procedures, data, and assumptions applied:

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* The method used was adapted from one given in an internal U.S. Environmental Protection Agency working memorandum from John W. Melone, Statistical Evaluation Staff, to Paul Stolpman, Office of Policy Analysis, 17 October 1978.

** Western coals were included, even though the ORBES scenarios prohibited the use of "nonlocal" coals.

- The total fuel-cycle cost, expressed in ¢/10^6 Btu, was calculated on a uniform basis. (Capital costs were annualized and added to the first year costs for this comparison of SIP options.) A 200-MW plant size was assumed. See Appendix E for assumptions regarding FGD costs.

- Pollution control at the power plant includes particulate and sulfur oxide emission reduction by electrostatic precipitator or baghouse and by either wet or dry scrubbers. PEDCo costs were assumed for wet scrubbing processes,[11,12] and EPA costs were assumed for dry scrubbing.[13] Dry scrubbing was assumed to be unavailable for plants complying with SIPs before 1983.

- It was assumed that cleaned coals would be processed to approximately "Level 3," which implies moderate sulfur and ash removal with a weight recovery of about 80 percent. A nominal charge of $3 per ton of cleaned coal was assumed.

- The assumed coal characteristics and origin/destination points are given in Tables B-7 and B-8.

- SIP standards were assumed to take effect after 1979.

To illustrate the procedure for estimating total fuel-cycle costs, we present in Table B-9 the specific data and assumptions for a typical power plant located near Springfield, Illinois. These data reflect a number of sources of information and incorporate primary coal data and the results generated by Teknekron's pollution control cost and performance models.[14]

The results show that the selection of coals and pollution control processes can be highly complex when all the cost-effective fuel-cycle choices are considered. They also show that, under the assumptions given in Table B-9, one cost-effective choice to meet most of the SO_2 emission limitations would be a central Appalachian bituminous uncleaned coal (CA/B/UC). This coal will require an FGD system in cases where the SIP limit for SO_2 is less than approximately 2.6 pounds per million Btu. Where the limit is higher, this coal can be burned without SO_2 emission controls. Only at an SO_2 emission limit of between 4 and 5 pounds per million Btu will the more "local" Illinois coal be more cost-effective, provided it is cleaned. Low-sulfur western coal (from the Powder River Basin) could provide for a lower total fuel-cycle cost at a SIP of about 1.5 lb SO_2 per million Btu. Considering all these specific circumstances, it

Table B-7

Typical Coal Characteristics

Coal	Uncleaned (UC) or Cleaned (C)	Average % Sulfur	Btu/lb	Average % Ash
1. Northern Appalachian (NA)	UC	2.60	12,000	9.90
2. Northern Appalachian (NA)	C	2.10	13,200	5.60
3. Central Appalachian (CA)	UC	1.60	12,000	8.00
4. Central Appalachian (CA)	C	1.20	13,200	4.40
5. Southern Appalachian (SA)	UC	2.05	12,000	8.20
6. Southern Appalachian (SA)	C	1.76	13,200	5.15
7. Interior Eastern (IE)	UC	3.60	11,000	10.30
8. Interior Eastern (IE)	C	2.60	12,100	6.00
9. Interior Western (IW)	UC	4.00	10,500	12.80
10. Interior Western (IW)	C	2.80	11,500	7.00
11. Central Western (CW)	UC	1.00	11,000	6.10
12. Powder River (PR)	UC	0.70	8,500	8.10

Table B-8

Typical Coal Supply-Demand Nodes

Supply Nodes		Demand Nodes	
Supply Region*/ Bituminous (B) or Subbituminous (SB)	Transport Origin	Consuming State	Transport Destination
NA/B	Pittsburgh, Pa.	Illinois	Springfield
CA/B	Charleston, W. Va.	Indiana	Indianapolis
SA/B	Chattanooga, Tenn.	Iowa	Des Moines
IE/B	Matoon, Ill.	Kentucky	Frankfort
IW/B	Kansas City, Mo.	Missouri	Jefferson City
CW/B	Grand Junction, Colo.	Ohio	Columbus
PR/SB	Gillette, Wyo.	Pennsylvania	Harrisburg
		Tennessee	Nashville
		West Virginia	Charleston

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* See Table B-7 for key to supply-region abbreviations.

Table B-9

Fuel-Cycle Costs for a Typical Power Plant near Springfield, Illinois
($1978/$10^6$ Btu)

Coal	F.O.B. Mine Price	Transportation Cost	Cost of Boiler Modification	Cost of Particulate Control	Cost of Sulfur Control	Control Type*	Total Cost	Potential SO_2 SIP (lb/10^6 Btu)
CA/B/UC	1.04	0.22	–	0.23	0.50	D	1.99	1.0
					0.30	D	1.79	2.0
							1.49	¢2.6
IE/B/UC	0.71	0.28	–	0.16	1.13	W	2.28	1.0
					0.98	W	2.13	2.0
					0.83	W	1.98	3.0
					0.70	W	1.85	4.0
					0.55	W	1.70	5.0
					–		1.15	¢7.6
IE/B/C	0.98**	0.26	–	0.15	0.91	W	2.30	1.0
					0.71	W	2.10	2.0
					0.52	W	1.91	3.0
					0.31	W	1.70	4.0
					–		1.39	¢4.9
PR/SB/UC	0.45	0.84	6.21	0.30	0.33	D	2.14	1.0
					–		1.80	¢1.7

* D = dry scrubber; W = wet scrubber.

** Includes coal cleaning.

appears that the central Appalachian coal provides for lower costs over a broader range of standards for this typical power plant near Springfield, Illinois.

Although this type of analysis illustrates the changes in coal choices that may accompany changing SIPs in a particular location, it should be noted, as explained in Section B.4, that "local" coals were prescribed in all cases in this Teknekron study of the ORBES area.

Before describing the selection of coals for the USM ORBES scenarios, it is appropriate to illustrate further the complexity involved in making coal and pollution control choices. Hence, we discuss below the factors surrounding the use of cleaned coals, taking as an example the case of the Conesville plant in Ohio.

Cleaned Coals as an SO_2 Compliance Option*

One plant in Ohio proposes to meet its new SO_2 standard by burning cleaned Ohio coals from currently used sources in four of seven units, with the cleaning to be done in new coal-cleaning facilities. The plant — the Conesville plant near Conesville in Coshocton County — is owned by the Columbus and Southern Ohio Electric Company (CSO).

Under the Ohio SIP, Conesville units 1-4, which represent about 70 percent of the plant's total six-unit capacity of 1,970 MW(e), must meet a limit of 5.66 lb SO_2 per million Btu; units 5 and 6 (which have FGD systems) must meet a 1.2 lb standard. Conesville's average SO_2 emissions in 1977 were (in lb per million Btu): 6.95 from units 1-3, 7.32 from unit 4, and 1.10 from unit 5. As of this writing, EPA and CSO have agreed that Conesville will comply with the SO_2 emission limit for units 1-4 by burning washed Ohio coals.

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* This discussion is adapted from reference 1.

At the same time, CSO is challenging the 5.66 lb limit on the grounds that it is unnecessarily stringent for plantwide compliance with the National Ambient Air Quality Standards. Whether or not this limit is relaxed, however, the utility prefers the cleaning of nearby Ohio coals as its SO_2 compliance strategy.

At present, all the coal burned at Conesville – about 3.73 million tons in 1977 – originates within about 15 miles from the plant, coming from five seams and 17 mines. About 25 percent comes from plant-site mining areas. Deliveries are by truck or conveyor belt. Since there are no rail or barge facilities, it is infeasible to use distant low-sulfur coal (from, say, eastern Kentucky or southern West Virginia) and especially desirable to continue using nearby Ohio coals.

Twenty percent of the coal currently used at Conesville comes from nearby parts of the Lower Kittanning (#5) and Pittsburgh (#8) seams. Since these coals are too high in sulfur, even after washing, the plant would discontinue using them. Eighty percent of the current supply comes from nearby parts of the Middle Kittanning (#6), Meigs Creek (#9), and Waynesburg (#11) seams; CSO would clean these coals. On the basis of washability tests it has conducted, CSO states that the cleaned coals can meet the 5.66 lb SO_2 standard for units 1-4. CSO is also considering the burning of these cleaned coals in the two units with FGDs in order to reduce limestone demand and the generation of scrubber sludge. Further, CSO is attracted by the possibility of improving plant performance through the use of physical coal cleaning (PCC).

CSO is considering coarse crushing (down to 2 x 0 inches) and a 1.6 specific gravity medium – a relatively low cleaning level often referred to as "Level 2." The company estimated tentatively that the resulting SO_2 level of the washed product will average 5.4 lb. We observe that, if we use an RSD of 0.08 for the 7,500 tons per day burned in units 1-4, the average SO_2 emissions corresponding to the allowable maximum emissions of 5.66 lb are 5.0 lb for a confidence level of 95 percent, and 4.6 lb for a confidence level of 99.87 percent. Therefore, the average post-PCC value of 5.4 lb estimated for the Level 2 cleaning may not allow an adequate design margin to account for sulfur variability. A more intensive level of coal cleaning or a somewhat greater selectivity of raw coals may, however, bring the product into line.

The Bureau of Mines washability data[10] include two samples from the Middle Kittanning seam in Coshocton County. Middle Kittanning is currently Coshocton's most productive seam, having produced 1.7 million tons in 1977, or about 45 percent of the county's coal output. While it is impossible to determine how representative the Bureau of Mines samples are of the current and future coal production from Coshocton's Middle Kittanning seam, it is interesting nevertheless to compare the PCC results for these samples with the results expected by Conesville. The two samples potentially emit 10.3 and 6.7 lb SO_2 per million Btu before cleaning. The first level of cleaning — "Level 2," which involves crushing to 1½ inch top size and a float-sink medium of specific gravity equal to 1.6 — corresponds to the level of PCC that CSO is considering. The second (more intensive) level, which we refer to as "Level 4," involves crushing to 3/8 inch top size and a specific gravity of 1.4.

When the relevant statistical factors require that the mean emissions not exceed 4.9 lb SO_2 per million Btu in order to meet a limit of 5.66 lb, Level 4 cleaning results in enough sulfur reduction from both the coal samples discussed. When the mean SO_2 emissions cannot exceed 4.5 lb SO_2 per million Btu, Level 2 cleaning allows compliance with the SO_2 standard only for the lower-sulfur coal sample; the higher-sulfur coal would require the more intensive PCC. In addition, several other observations can be made.

- The percentage of coal ash drops from 13.5 to 4.7 and 3.2 when Levels 2 and 4 are applied to the first coal, and from 10.2 to 4.8 and 3.4 when they are applied to the second coal.
- The Btu losses resulting from PCC are significantly higher for the more intensive level of cleaning: 16 percent and 9 percent, as compared with 8 percent and 2 percent for the lower level of PCC. (Monetary costs are necessarily attached to the energy losses.)
- The laboratory procedures used in the Bureau of Mines washability tests commonly employ heavy organic liquids to obtain desired specific gravities of separation. Heavy organic liquids promote a greater degree of sulfur removal (for the same specific gravity) than does water (made denser with materials such as magnetite), which is

the basic separating medium normally used in commercial PCC operations.

- The heating values and sulfur and ash contents listed in Table B-10 are presented on a moisture-free basis, so that they are higher than those for coal on an as-received basis. For lb SO_2 per million Btu, however, the moisture-free and as-received values are not very different.

To put Conesville's proposal — "clean nearby Ohio coals" — in perspective, we present Table B-11, which lists selected characteristics of analytical samples from the Middle Kittanning seam in Coshocton County, as reported by the Ohio Geological Society. Measured heating values and percentages of ash and sulfur (total, pyritic, and organic) are listed in columns 1-5 of the table. Computed values of potential emissions of total sulfur and organic sulfur as lb SO_2 per million Btu are shown in columns 7 and 8. Column 9 lists the organic-sulfur SO_2 emissions of column 8 reduced by an assumed value of 10 percent, to reflect an estimated upgrading of 10 percent in the heating value following PCC. Since essentially no organic sulfur is removed by PCC, emissions of only the organic-sulfur component represent the theoretically lowest SO_2 emissions from a cleaned coal, assuming no sulfur retention in the ash. While in practice this theoretical limit will not be achieved, we list it as a guide for understanding Conesville's planning. Certainly, if these theoretically best values were significantly higher than an allowable mean emission (about 4.5 to 4.9 lb SO_2 per million Btu for a clean-coal RSD of 0.08), and if the measured samples were fairly representative of available coal from the Middle Kittanning seam in Coshocton, the proposed coal-cleaning SO_2 compliance strategy would not appear worth considering. Since, however, most of the SO_2 emissions listed in the last column are below the allowable mean limit for units 5-7, PCC does appear to merit consideration.

The question at this point is, How will the "theoretically minimum" SO_2 emissions depicted in the last column of Table B-11 correspond, in fact, to actual SO_2 emissions from the Coshocton County/Middle Kittanning coals? The answer, of course, will depend on the particular coal and PCC process. For the data representing the two samples in Table B-10, the "theoretically minimum"

Table B-10

Summary of Results of Bureau of Mines Washability Tests on Two Samples from the Middle Kittanning Seam in Coshocton County, Ohio

	Raw Coal					After Level 2 Cleaning						After Level 4 Cleaning					
				Sulfur %						Sulfur %						Sulfur %	
Sample	Btu/lb	Ash %	lb SO_2/ 10^6 Btu	Total	Pyritic	Btu Loss	Ash %	Btu/lb	lb SO_2/ 10^6 Btu	Total	Pyritic	Btu Loss	Ash %	Btu/lb	lb SO_2/ 10^6 Btu	Total	Pyritic
1	12,300	13.5	10.3	6.4	4.5	8%	4.7	13,590	4.9	3.4	1.5	16%	3.2	13,810	4.0	2.8	1.0
2	12,500	10.2	6.7	4.2	2.3	4%	4.8	13,300	4.2	2.8	1.1	9%	3.4	13,490	3.6	2.5	0.7

Source: Joseph A. Cavallero et al., Sulfur Reduction Potential of the Coals of the United States, Bureau of Mines RI 8118 (Pittsburgh, Pa: U.S. Department of Interior, Bureau of Mines, 1976).

Note: Level 2 here designates crushing to 1½ inch top size and a float-sink medium with specific gravity equal to 1.6. Level 4 designates crushing to 3/8 inch top size and a specific gravity of 1.4.

Table B-11

Ash and Sulfur Contents of Coal Samples from Middle Kittanning Seam, Coshocton County, Ohio

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		% Sulfur				lb $SO_2/10^6$Btu		
Heating Value (Btu/lb)	%Ash	Total	Pyritic	Organic	lb Ash/ 10^6 Btu	Total S before PCC	Organic S before PCC*	Organic S after PCC*
12880	5.1	3.5	1.22	2.0	4.0	5.4	3.1	2.8
9980	5.0	6.7	3.2	3.25	5.0	13.4	6.5	5.9
12220	4.9	4.2	1.67	2.28	4.0	8.4	4.5	4.1
10510	5.2	8.9	5.19	2.72	4.9	16.9	5.2	4.7
12880	2.7	4.3	2.11	2.16	2.1	6.7	3.4	3.1
12330	3.3	5.4	2.86	2.24	2.7	8.8	3.6	3.3
12580	4.4	3.5	1.3	1.67	3.5	5.6	2.6	2.4
13350	4.5	2.3	0.97	1.27	3.4	3.4	1.9	1.7
10030	7.1	6.5	3.84	1.79	7.1	13.0	3.6	3.3
12300	4.8	3.6	1.59	1.57	3.9	5.9	2.6	2.7
12860	4.0	4.0	1.67	1.77	3.1	6.2	2.8	2.5
12730	3.2	3.6	1.25	1.84	2.5	5.7	2.9	2.6
10270	2.9	4.5	2.17	1.98	2.8	8.8	3.8	3.4
12230	3.6	4.0	1.68	1.83	2.9	6.5	2.9	2.6
11950	5.7	5.3	2.96	2.05	4.8	8.9	3.5	3.2
12800	5.5	3.9	1.76	2.13	4.3	6.1	3.4	3.1
13130	5.4	3.7	1.16	2.47	4.1	5.6	3.8	3.4
9070	5.9	6.7	4.06	2.14	6.5	14.8	4.7	4.3
11980	5.6	4.5	2.15	2.22	4.7	7.5	3.7	3.4

Source: G. Botoman, and B. Smith. Analyses of Ohio Coals, IC No. 47 (Columbus, Ohio: Ohio Geological Survey, 1978).

Note: Samples were taken in 1976. Values listed are for as-received coals.

* Values for lb $SO_2/10^6$ Btu are based on the assumption that all sulfur is emitted as SO_2. Values for organic sulfur after physical coal cleaning are based on the assumption that the heating value of the cleaned coal is 10 percent higher than that of the raw coal; these values represent a lower bound on SO_2 emissions following PCC (i.e., all pyritic sulfur removed by PCC).

values would be multiplied by factors of 1.4 and 1.3 for Level 4 PCC. These data, then, suggest that a certain amount of blending of cleaned coal with low-sulfur coal may be required.

To some extent, excess emissions from units 1-4 could be offset by decreases in emissions from the two units with FGD systems, which could result if those units burned some cleaned coal.

While more data and further analysis are needed to determine whether PCC can be the exclusive SO_2 control strategy for Conesville's units 1-4, Table B-10 does show that without PCC the use of the nearby Middle Kittanning coals would be out of the question. Certainly PCC would significantly increase the potential for using these coals. CSO is attracted further by other consequences of PCC: the removal of incombustible material, the expected decrease in gas flow during combustion, and the possibility of raising the coal's ash fusion temperature. The technical aspects of PCC do, therefore, seem attractive. But there remain a number of insistent and important institutional questions, which relate to the fact that, although SO_2 compliance was required in Ohio by October 1979, the PCC facilities needed by Conesville do not exist:

- Under what institutional arrangement will the needed PCC facilities be built?
- When will they be operational?
- What strategy for SO_2 compliance will Conesville follow until it can use PCC? Will Conesville be allowed a variance in SO_2 emissions during construction of a PCC facility? And if a variance is not granted, what will happen vis-a-vis the disuse of local mines and possibly the construction of needed transportation facilities (assuming no FGD) during development of the PCC facilities?

Accounting for the need to acquire relevant information, to carry out feasibility and design studies, and to obtain approval from EPA and other regulatory agencies, Conesville estimates that adequate PCC facilities could not realistically be expected to come on line before about the spring of 1982. Meanwhile

CSO plans to support studies to determine the optimum ownership, construction, and operational arrangements for PCC. Conesville's preliminary cost estimates suggest that, if Level 2 PCC is implemented and does meet the SO_2 standards, consumers will see about a 2 percent (uninflated) increase in their cost of electricity (reflecting about a 7 percent increase in fuel costs). An analysis of the net costs will necessarily address the following questions:

- What will the levelized capital and operating costs of the PCC facilities be, and what will the associated incremental fuel costs be?
- What power-plant benefits or problems — other than those related to SO_2 compliance — will result from PCC?

In general, a utility will perceive the net monetary cost of PCC, for specifed PCC levels and coals, in terms of two main sets of factors. The first set translates into an incremental price of delivered coal, which reflects mainly (1) the capital and operating costs associated with the PCC plants, and (2) the loss of Btu during PCC, and (3), to a lesser extent, other items such as reduced transportation costs and reduced payments for miners' benefits. (For example, at Conesville the adoption of PCC may reduce the need to build rail facilities.) The second set of factors relates to the combustion of cleaned rather than raw coal at the power plant (for given environmental regulations and operating conditions): burning cleaned rather than raw coals generally results in monetary benefits (often difficult to quantify) having to do with the pulverizers, the boiler, the particulate control equipment, and storage and disposal requirements. PCC may reduce the need for building rail facilities. Further, any reduction in sulfur variability resulting from PCC will increase the coal purchaser's options and therefore his bidding position. Finally, there is the argument that PCC may reduce the need for unemployment or welfare payments by enhancing the competitive position of locally produced coal. All these factors can influence the cost of using cleaned coals compared with other options and are currently under study.

B.4 Coals Selected for the USM ORBES Scenarios

Although the results of the Teknekron analysis described at the beginning of Section B.3 allowed for a cost-based selection of coal by power-plant regulatory category, the ORBES scenario assumptions dictated that nonlocal (non-ORBES-area) coals be excluded from this study. Hence, only local Appalachian and interior eastern coals (the first eight coals listed in Table B-7) were considered for compliance within the ORBES counties.

Coal selection proceeded as follows. For every ORBES state, each of the eight representative "local" coals was characterized by its chemical and physical characteristics, its delivered price, its supply location, and the applicable SIP, NSPS, and RNSPS emission limitations. The characteristics of the coals historically used, representing average conditions for each state in the region, were determined from Federal Power Commission data for 1976. From these data we derived average annual coal characteristics (heating value, sulfur content, ash content). Data on historical fuel prices and fuel price trends were obtained from the National Coal Association's 1977 Steam Electric Plant Factors.[15] Table B-12 presents a state-by-state listing of the representative characteristics of the coals used in the ORBES counties during 1976 and used in the USM for these projections. The SIP plants are categorized as subject to either an urban or a rural SIP depending on the level of the assumed standard in the plant's county of location.

Future coals were selected to meet the SO_2 regulation assumed for each county. For each power-plant regulatory category (SIP, NSPS, and RNSPS), the costs incurred at every stage of the coal fuel cycle — mining, transportation, cleaning, boiler modification, and pollution control — were summed, as illustrated in Section B.3, for each of the eight possible coals. Then a life-cycle cost algorithm[16] was utilized for each element of the coal fuel cycle so that appropriate technical and economic assumptions could be examined. The life-cycle cost algorithm incorporated cost and performance models of various pollution control and coal preparation processes to ensure that cost-based trade-offs would be addressed. The life-cycle costs incurred throughout the fuel cycle

Table B-12

Representative Characteristics of the Coals Used in the ORBES States in 1976

	Plants Governed by Urban SIPs					Plants Governed by Rural SIPs				
State	Average Btu/lb	Average % Sulfur	Average % Ash*	Average \$/Ton	Average \$/10^6 Btu	Average Btu/lb	Average % Sulfur	Average % Ash*	Average \$/Ton	Average \$/10^6 Btu
Illinois	10527	2.8	11.1	15.22	0.720	10572	3.2	11.1	18.23	0.856
Indiana	10876	2.8	11.4	14.32	0.658	10887	3.5	11.4	11.57	0.530
Kentucky	10946	3.6	15.6	16.66	0.761	10964	3.1	15.6	14.25	0.644
Ohio	10824	2.6	16.0	20.22	0.933	10794	3.1	16.0	19.52	0.910
Pennsylvania	11860	2.3	16.2	20.33	0.858	12046	2.3	16.2	22.75	0.948
West Virginia	11610	0.9	15.4	23.41	1.008	11825	2.3	15.4	20.90	0.881

* Ash is computed as a weighted average from FPC Form 67 for the years 1973 and 1974.

were then summed for each coal. In Table B-13, we summarize the characteristics of predominant coals produced and consumed in the ORBES counties. In Table B-14, projected delivered prices for these coals are given in 1975 dollars.

Table B-13

Characteristics of Predominant Coal Supplies for the ORBES Counties in the Year 2000

No.	Coal, by Supply Region	Uncleaned or Cleaned	Average Percent Sulfur	Btu/Lb	Average Percent Ash	Abbreviation	States Encompassed in Supply Region
1.	Northern Appalachia	UC	2.60	12,000	9.87	NA/BUC	Ohio, Pennsylvania, northern West Virginia
2.	Northern Appalachia	C	2.10	13,2000	5.63	NA/B/C	Ohio, Pennsylvania northern West Virginia
3.	Central Appalachia	UC	1.60	12,000	8.00	CA/B/UC	Maryland, southern West Virginia, eastern Kentucky
4.	Central Appalachia	C	1.20	13,200	4.40	CA/B/C	southern West Virginia, eastern Kentucky
5.	Interior Eastern	UC	3.60	11,000	10.30	IE/B/UC	Illinois, Indiana, western Kentucky
6.	Interior Eastern	C	2.60	12,100	5.98	IE/B/C	Illinois, Indiana western Kentucky

Table B-14

Delivered Price of Coal (1975¢/Million Btu)

State	Regulatory Category	Coal Abbreviation*	Sulfur lb/10^6 Btu	Price/Year		
				1976	1985	2000
Pennsylvania	Urban SIP	NA/B/C	1.59	125.6	144.7	212.9
	Rural SIP	CA/B/UC	.90	106.2	137.9	230.5
	NSPS	NA/B/UC	2.17	101.9	117.4	173.6
	RNSPS	NA/B/UC	2.17	101.9	117.4	173.6
Ohio	Urban SIP	CA/B/C	.70	124.8	160.3	261.5
	Rural SIP	NA/B/UC	2.17	88.5	102.0	150.9
	NSPS	NA/B/UC	2.17	88.5	102.0	150.9
	RNSPS	NA/B/UC	2.17	88.5	102.0	150.9
Indiana	Urban SIP	CA/B/C	.91	122.7	157.6	257.1
	Rural SIP	IE/B/UC	2.50	83.2	101.4	135.4
	NSPS	CA/B/UC	1.33	97.7	126.8	212.0
	RNSPS	IE/B/UC	3.27	83.2	101.4	135.4
Illinois	Urban SIP	IE/B/C	2.15	124.1	151.5	202.8
	Rural SIP	IE/B/UC	3.00	79.4	96.8	129.3
	NSPS	SA/B/UC	1.71	100.5	119.6	195.0
	RNSPS	IE/B/UC	3.27	79.4	96.8	129.3
West Virginia	Urban SIP	CA/B/UC	1.33	91.7	119.1	199.1
	Rural SIP	CA/B/UC	1.33	91.7	119.1	199.1
	NSPS	CA/B/UC	1.33	91.7	119.1	199.1
	RNSPS	CA/B/UC	1.33	91.7	119.1	199.1
Kentucky	Urban SIP	CA/B/C	.91	131.1	168.4	274.6
	Rural SIP	IE/B/UC	2.85	87.7	106.9	142.8
	NSPS	CA/B/UC	1.33	96.4	125.2	209.3
	RNSPS	CA/B/UC	1.33	96.4	125.2	209.3

* See Table B-13 for name of coal.

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APPENDIX C

PROJECTIONS OF DEMAND GROWTH AND COMPUTATION OF PRICE AND INCOME ELASTICITIES

C.1 Pertinent Characteristics of the Utility Simulation Model

C.2 Modifications of the USM to Produce Price- and Income-Sensitive Demand Forecasts

C.3 References

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APPENDIX C

PROJECTIONS OF DEMAND GROWTH AND COMPUTATION OF PRICE AND INCOME ELASTICITIES

In this appendix we present a method of calculating price- and income-sensitive demand for electricity and of deriving price and income elasticities of the demand for electricity in the ORBES counties. The Utility Simulation Model (USM) was modified as described below in order to forecast price- and income-sensitive demand in addition to matching the forecasts specified by the ORBES scenario specifications.

C.1 Pertinent Characteristics of the Utility Simulation Model

Several characteristics of the USM's demand and economic forecasts (produced by the DEMAND and FINANCIAL modules, respectively) should be explained, because they directly affect the method chosen to introduce price and income sensitivities into the demand forecasts.

First, the prices forecast by the FINANCIAL module are average, not marginal, prices. Price forecasts are calculated for retail and wholesale customer classes based on the state-firm's* revenue requirements and allowed costs of service. Second, the implicitly assumed rate "structure" used in the USM is a simple flat rate schedule for retail and wholesale customer classes. Third, the USM offers the choice of (a) using state population forecasts together with national or regional per capita electricity consumption growth rates as a basis for forecasting electricity demand, or (b) scaling energy growth rates for the relevant electric reliability councils on the basis of relative population growth to satisfy exogenously specified demand levels, or (c) using state-specific demand growth rates derived from utility submissions to regional reliability councils. The latter two methods have been used to reproduce the aggregate ORBES county demand projected by other ORBES researchers.

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* See Appendix D.

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Finally, prior to this application there was no formal linkage between the USM FINANCIAL module, which produces the average price forecasts, and the USM DEMAND module, which produces demand forecasts for the simulated electric utilities.

C.2 Modifications to the USM to Produce Price- and Income-Sensitive Demand Forecasts

The modifications that have been made to the USM allow the model user to produce forecasts of electricity demand that account for changes in both average electricity prices and the consumer's disposable personal income. It should be understood, however, that these modifications to the method of forecasting the demand for electricity do not produce an equilibrium solution. With these changes, the USM can provide price- and income-adjusted demand forecasts based on a limited-iteration adjustment method. But in order to produce an equilibrium solution, the DEMAND and FINANCIAL modules would have to be directly interfaced to provide direct computation of the equilibrium prices for each simulation year, subject to the demand sensitivities, the state-firm's costs of service, and the state-firm's revenue requirements.

Such changes would have required major reprogramming and modification of the model's structure and operations. Since adjustments of that magnitude were not feasible, the modifications described below were carried out. These modifications involved less significant reprogramming but approximated reasonably the impacts of changes in electricity prices and disposable income. The modifications consisted of two interrelated procedures; first, a change in the manner of calculating yearly electricity demand growth; and second, introduction of a method for calculating price and income elasticities of demand.

Forecast of Electricity Demand Growth

First, the USM DEMAND module was modified so that the calculated yearly energy growth rate can be optionally specified as a function of price and income changes. The form of the linear first-order difference equation for forecasting the energy growth rate, E, is given in equation (1).

$$\Delta E_{it} = \alpha + \beta \epsilon_p(\Delta P_{it}) + \gamma\ \epsilon_y(\Delta Y_t) + \mu \qquad (1)$$

The sources of historical data for the parameters in equation (1) are shown in Table C-1.

The delta operator (Δ) defines the ratio of the value of the variable in year t and year t-1. Where ϵ_p is the own-price elasticity,* ΔP is the ratio of the price of electricity for state i in year t to the previous year's price, ϵ_y is the income elasticity, ΔY is the ratio of disposable income in year t to the previous year's disposable income, and μ is the error term.

The own-price elasticity (ϵ_p) and income elasticity (ϵ_y) terms can be specified by the user and are calculated below (see discussion below under Calculation of Price and Income Elasticities). For this analysis, several estimates of price and income elasticity were used. The projected yearly price changes (ΔP_{it}) were obtained by running the USM FINANCIAL module for ORBES Scenario 2. The FINANCIAL module produces the initial forecasts of yearly price changes. These forecasted price changes are then inserted into equation (1) as a vector. Clearly, the user has the option of simulating as many iterations of these prices as he deems appropriate. For each iteration, the user simply computes the

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* The term "elasticity" is a dimensionless ratio referring to the relative change in the quantity of the demanded good (in this case, electricity) given a change in an independent variable (e.g., price, income). Thus, if the price elasticity of demand is -1.5, a 1 percent increase in electricity price will lead consumers to decrease their electricity demand by 1.5 percent.

Table C-1

Sources of Historical Data for the Parameters in Equation (1)

Parameter	Description	Data Source*
ΔE	The yearly percentage change in kWh sales for the total electric utility industry minus one	EEI
ΔP	The yearly percentage change in average revenue/kWh sold to total ultimate customers for the total utility industry minus one	EEI
ΔY	The yearly percentage change in national disposable personal income minus one	BEA
ϵp	Own-price elasticity of demand	Calculated
ϵy	Income elasticity of demand	Calculated

* EEI: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry for 1977 (January 1, 1978). BEA: U.S. Department of Commerce, Bureau of Economic Analysis, as reported in the Economic Report of the President (Washington, D.C., January 1977).

yearly price changes from the previous FINANCIAL module results, inserts these calculated yearly price changes into equation (1) of the DEMAND module, and then reruns the simulation.

As with the price elasticity estimate, income elasticity (ϵ_y) can be specified by the user. The yearly changes in disposable personal income (ΔY_t) that were used in the USM were produced by the Wharton Econometric Forecasting Associates macroeconomic model. Because yearly disposable income projections were not then available for the ORBES counties, the assumption was made that income growth rates for the nation were applicable to them.

The remaining parameters in equation (1), β and γ, act as weighting factors to distribute that portion of energy growth that is attributable to price and income changes. Using yearly national data for the 1963-1976 period, these coefficients were derived for equation (1) using ordinary least squares. Data for electricity sales growth (ΔE_t), for average price changes for ultimate customers (ΔP_t), and for changes in disposable income (ΔY_t) were gathered from the Commerce Department's Bureau of Economic Analysis. Although this is a limited time-series, especially since the data are annual, it covers a period of changing customer demand and provides useful observations for the regression analysis of equation (1).

The estimated coefficients are given in Table C-2 with the t-statistics in parentheses. These estimates are all significant at the 0.05 confidence limit and explain a significant portion (90 percent) of the change in yearly electricity growth. The Durbin-Watson statistic (DW) provides assurance that serial correlation is not a problem.

Because the USM forecasts yearly peak demand growth as well as energy growth, an attempt was made to provide economic-based peak load forecasts similar in structure to that of the energy forecast in equation (1). However, such an equation could not be successfully estimated. The reasons for the difficulty are well known to analysts of peak electricity demand forecasts (see references 1, 2, 3, 4, 5, and 6) and include the problem of defining the peak period price of

Table C-2

Regression Results for Equation (1)

Coefficient	Using Witt Elasticities*	Using Teknekron Elasticities**
α(constant)	0.0471 (3.64)	0.0471 (3.64)
β(price)	0.4318 (9.69)	0.3557 (9.69)
γ(income)	0.3966 (3.64)	0.4883 (2.63)
R^2	0.90	0.90
DW	1.90	1.90
	Assumed Elasticities	
ϵ_p	-0.79	-0.96
ϵ_y	0.97	0.77

Note: t-statistics appear in parentheses.

* P.C. Mann and T.S. Witt, "Economic Analysis of the Electric Utility Sector in the Ohio River Basin Region," Report prepared for Ohio River Basin Energy Study (Morgantown, W. Va.: West Virginia University, June 1979), Table 11.

** See discussion below under Calculation of Price and Income Elasticities.

electricity when very few utilities employ time-of-use rate schedules for their smaller customers. These difficulties in forecasting peak demand have been discussed[4] and could not be dealt with adequately in this analysis. Therefore, because of significant data-availability problems and the lack of adequate resources given the problem's scope, no further attempt was made to introduce economic variables into the DEMAND module's peak demand growth forecast algorithm.

Calculation of Price and Income Elasticities

The introduction of equation (1) into the DEMAND module's forecast algorithm for the yearly energy growth rate allows for specification of both price and income elasticities. A number of analyses have estimated these elasticities of demand[7] using an impressively broad range of estimation methods and data sources. However, estimated price and income elasticities of demand for the ORBES region could not be found in the literature. For this reason, a modest effort was undertaken to calculate these elasticities.

At this point, it is important to remember that the USM projects the average electricity prices for retail customers. Economic theory dictates that marginal, not average, price is the relevant explanatory variable in estimating customers' demand. As has been discussed by other investigators, existing econometric studies generally have not dealt adequately with this issue.* Therefore, although there are well-founded theoretical reasons for using marginal prices in the demand functions to be estimated, a straightforward ex post average price term was used.

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* Much of the discussion has focused on whether to use an average or marginal price rather than on the more generic and important issue of how to introduce the complete rate schedule (which is, of course, a series of prices) upon which the quantity of electricity consumed depends. Reports by Acton et al.[8] and Taylor et al.[9] illustrate two attempts to include the rate schedule into the demand function being estimated.

The principal difficulty in using ex post prices calculated from data on sales revenues and kWh consumption is that a simultaneity problem is created. This is because the price data used as an explanatory variable in the demand function are related to the function's dependent variable, kWh consumed. Several investigators, such as Halvorsen,[10,11] have attempted to surmount this simultaneity problem in the use of ex post prices by specifying both a supply and demand function.

Two sets of price and income elasticities for the ORBES counties were used for this analysis, as illustrated in Table C-2. The first set of elasticities was estimated by Professor Tom Witt for the ORBES project and was presented in his and Patrick Mann's paper, "An Economic Analysis of the Electric Utility Sector in the Ohio River Basin Region."[12] The method Witt used in arriving at his estimates is described in the above-cited report and is summarized here briefly. The price and income elasticities estimated by Witt are based on an analysis undertaken by Chem at al.[13] at Oak Ridge National Laboratory. The Oak Ridge elasticities were weighted to reflect price and income elasticities for the six-state ORBES area. The long-run average price elasticity and the long-run income/output elasticity for the ORBES area were estimated by Witt to be -0.79 and +0.97, respectively (see his Table 11).

The second set of price and income elasticities was estimated by Teknekron in the following manner. Because of the structure and operation of the USM, as mentioned above, ex post average prices were used. Thus, the demand function used to estimate the price and income elasticities contains the problems associated with the use of an ex post average price term because the USM forecasts only average prices. In addition, the demand function estimated requires the price and income elasticities for total retail customers in order to be consistent with the USM structure. It is preferable to distinguish between residential, commercial, and industrial customer demand elasticities; but, because the current USM DEMAND module classifies customers only as either retail or wholesale, such customer class distinctions were not pertinent.

There are two generic types of demand models that can be used to characterize the demand for electricity: flow-adjustment models and stock-adjustment models. In different ways, both types of models attempt to account for the fact that electricity is consumed not as an end in itself but as a derived demand. That is, the demand for electricity stems from the consumer's wish to undertake productive work, not from his wish to "use" kWh or kW themselves. A person who wants to cool his home, for example, is not actually demanding kWh. Rather, he is demanding air conditioning, which requires electricity to power the compressor. Similarly, commercial and industrial demands for electricity are not demands for kWh or kW per se, but for heating, cooling, lighting, and processing, all of which, again, require electricity.

The stock-adjustment models explicitly account for the derived nature of the demand for electricity and assume that this demand can be characterized by identifiable end-uses (e.g., heating, lighting, processing). These models assume that the stock of electricity-using capital goods is measured in terms of the demand (kW) levels of electricity this stock can utilize. Thus, forecasting demand is converted into forecasting (a) the level of utilization of the existing stock of appliances and equipment, and (b) the adjustment process in adding to this stock over time.

Several investigators have attempted to develop such stock-adjustment demand models (see references 5, 6, 7, 8, and 9). The advantage of such models compared with the flow-adjustment models is that their characterization of the electricity demand process is more logical and refined. Unfortunately, however, the data they require are significantly more detailed. These data must include information on the level of appliance stocks (by type of appliance), the level of equipment stocks by type, and these stocks' utilization rates for each utility or state being examined by the model. Although such data do exist, those for the ORBES area were not readily available. Thus, while a stock-adjustment model would have offered certain advantages, significant data problems prevented its use for this application.

The flow-adjustment models offer the advantage of more reasonable data requirements, but only indirectly do they reflect the stock of electricity-using capital goods. The majority of econometric demand models that have been estimated are flow-adjustment models, in which price, income, and other variables are used to explain the demand for electricity.

The model that was chosen for estimating ORBES demand elasticities is a flow-adjustment model based on a formulation used by Houthakker, Verleger, and Sheehan.[14] This rather straightforward functional form has the advantage of modeling the demand for electricity as a flow, which is consistent with the USM's modified method of forecasting the demand for electricity. Also, it is easily estimated, because data for each of the major variables are readily available. This formulation, modified to account for differences in the selected ORBES states, is presented in equation (2).

$$\ln Q_d = a \ln P + b \ln Y + C\ STD + d \qquad (2)$$

The sources of historical data for the parameters in equation (2) are shown in Table C-3. In equation (2), Q_d is the quantity of electricity demanded per customer, P is the average price of electricity for retail customers, Y is per capita disposable income, STD is a state dummy variable, and d is the error term. Data were collected on a cross-sectional basis for 1975, with the units of observation being the privately owned electric utilities that have generating equipment and/or service areas in the ORBES counties. The estimated coefficients a and b represent the price and income elasticities, respectively.

As stated before, the price variable (P) represents the ex post average price for retail customers calculated from Federal Power Commission data. The income variable, derived from data published by the Commerce Department's Bureau of Economic Analysis (BEA), represents a weighted average of per capita income for SMSAs and cities in each utility's service area. The 1975 income data were gathered from the BEA publication "Local Area Personal Income, 1971-1976."

Table C-3

Sources of Historical Data for the Parameters in Equation (2)

Parameter	Description	Data Source*
Q_d	Total kWh sales to ultimate customers	FPC
P	Average revenue/kWh sold to ultimate customers	FPC
Y	Per capita income	BEA
STD	Dummy variable for each state	

* FPC: Federal Power Commission, Statistics of Privately Owned Electric Utilities in the U.S. (Washington, D.C., 1975). BEA: U.S. Department of Commerce, Bureau of Economic Analysis, "Local Area Personal Income, 1971-1976" (Washington, D.C., 1977).

A list of cities and SMSAs served by each of the utilities examined was produced. In cases where two or more utilities served one SMSA (e.g., Cincinnati), the SMSA was divided into the counties served by each utility and the per capita income figures were taken at the county level. If the utility served no SMSA, then the per capita income data were gathered on a county basis. In this way, data were gathered from 33 SMSAs and 32 counties, representing over 150 different cities in the ORBES area. Finally, the BEA income data were adjusted to reflect disposable income rather than personal income in 1975.

Several variables were considered and used to account for potential differences between the different states in the ORBES area not explained by the price and income data. Such variables can turn out to be important, since the explanatory power of the demand equation rests heavily on price and income variations. These state variables included a state dummy variable and the percentage of population residing in rural areas in 1975.* Neither of these variables significantly increased the explanatory power of the estimated equation or was statistically significant. This result indicates that the ORBES area can be considered homogenous across the explanatory variables considered.

The estimated price and income elasticities for retail customers are given by the following econometric estimates of equation (2) using ordinary least squares:

$$\begin{aligned} \ln Q_d = {} & \underset{(-4.73)}{-0.9591 \ln P} + \underset{(8.76)}{0.7677 \ln Y} \\ & + \underset{(1.06)}{0.8623\text{E-}06\ \text{STD}} \qquad R^2 = 0.42 \end{aligned}$$

With the exception of the state dummy variable coefficient (STD), each of the estimated coefficients is significant at the .01 confidence limit. The explanatory power of the equation is not high but acceptable, given the fact that these estimates are based on cross-sectional data.

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* The 1975 percentage of population in rural areas was calculated from census data and transformed using Newton's Forward Interpolation method.

From these results, we see that the estimated elasticities have the theoretically expected signs. The price elasticity, however, is below several other cross-sectional estimates, which are all larger than minus one.* This elasticity (-0.9591) should be considered marginally inelastic. One possible explanation is that consumers' long-run elasticity has declined over time, as electricity prices have increased an average of 9.6 percent per year since 1970 after a decade-long period of relative price stability. Because other investigations generally ended with 1970 data, they could not have examined the cumulative effects of a continuing period of rising prices; thus, their price elasticity estimates may be biased upwards.

The estimated income elasticity, +0.7677, is well within the range of other published estimates. Although comparisons are difficult — because, like the estimated price elasticity, this income elasticity represents that for all retail customers, not specific customer classes — we note that the only other income elasticity using cross-sectional data, reported by Taylor,[7] was estimated to be +0.80 for residential customers.

In summary, this appendix has presented estimates of price and income elasticities for the ORBES area that can be used within the modified DEMAND module of the USM. The design of the demand forecast algorithm allows use of these or other relevant price and income elasticities. The price elasticities estimated are comparable to available national estimates but are somewhat lower than other selected estimates.

One important final note concerns the apparent problem of using long-term price and income elasticities in a model (the USM) that forecasts short-term (yearly) demand and price changes. Fortunately, this problem has been addressed by the formulation of the demand forecast equation given in equation (1). This is because the long-run elasticities are multiplied by the weighting coefficients estimated in equation (1) to produce an effective elasticity that can be characterized as a hybrid elasticity more suitably used in a yearly forecast. The effective price elasticity for retail customers thus becomes -0.34; and the effective income elasticity for retail customers becomes +0.37.

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* The reader should remember that comparisons are made more difficult since this elasticity estimate is for all retail customers, not a specific customer class.

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APPENDIX D

THE CALCULATION OF ECONOMIC AND FINANCIAL IMPACTS

D.1 The FINANCIAL Module of Teknekron's Utility Simulation Model

D.2 FINANCIAL Module Assumptions

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APPENDIX D

THE CALCULATION OF ECONOMIC IMPACTS

In this report we have assessed the economic impacts of the future operations of electric utilities in the ORBES counties. The principal analytical tool for this assessment was the FINANCIAL module of the Utility Simulation Model (USM). The FINANCIAL module works in conjunction with the other modules of the USM so that the economic and financial results are consistent with technical and environmental projections. As with many types of forecasts, it is usually more important to consider the relative effects of the projections rather than their absolute levels.

Several qualifications may be made regarding our assessment. First, we have not attempted to identify and compare the largely nonquantifiable private and social benefits that may be realized from various utility futures. Some of these have, however, been treated elsewhere in the ORBES study — in some cases utilizing our projections.

Second, as is true for any forecast of future events, uncertainty surrounds the projections of the relative economic impacts. We believe, however, that the FINANCIAL module, operating in conjunction with the rest of the Utility Simulation Model, has generated as useful and comprehensive a set of projections under the selected assumptions as can be obtained.

Third, there are several regulatory agencies besides the state and federal environmental agencies that influence utility operations and performance. State public utility commissions and, in the case of publicly owned utilities, utility districts or local regulators, exert predominant authority over the utility's financial position. As its name implies, the rate-of-return regulation implemented by the state PUCs and the Federal Energy Regulatory Commission* establishes an "allowed" rate-of-return for the utility. This return and the utility's performance then directly influence the firm's ability to raise capital. Federal environmental regulations are but one set of several regulatory mechanisms that the utilities face in their interactions with the nation's financial markets. Although pollution control investments made by the utility industry as a result of state and federal environmental regulations are growing, they will still represent a fraction of the industry's total capital requirements over the next two decades. The utilities' ability to raise this capital will be affected by state PUC policies and practices and by the prevailing economic climate.

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* Formerly the Federal Power Commission.

D.1 The Financial Module of Teknekron's Utility Simulation Model

The FINANCIAL module provides economic and financial information to complement the wealth of technical and environmental data produced by other modules of the Utility Simulation Model. Table D-1 lists the inputs that are passed to the FINANCIAL module from other modules. The FINANCIAL module uses this information as well as internal computations for interest, depreciation, taxes, financing, and rate setting to produce annual simulated financial statements. These financial statements include an income statement, balance sheet, source and use of funds statement, and other financial statistics for both investor-owned and publicly owned electric utilities.

The FINANCIAL module acts as an interface of the demand and supply models by means of a computational module that calculates prices at which revenues are in balance with costs. It constitutes a simulation of regulatory control. But, strictly speaking, it is impossible to carry out a computer simulation of the regulatory process. Computer simulation implies that prices are determinable from cost information, or from similar data, by definite mathematical formulas. This is often not the case. Rather, the regulatory commissions (or similar public regulatory authorities) are deliberative bodies. They consider a wide range of facts and hear opposing views expressed in a formal hearing. In making their judgments they may be called upon to resolve problems when accepted principles are in conflict.

Table D-1

Input Values Passed to the FINANCIAL Module by Other USM Modules

DEMAND INFORMATION	from DEMAND
• Sales to ultimate consumers	
• Sales for resale	
OPERATING DATA	from DISPATCH
• Fuel expense	
• Operation expense	
• Maintenance expense	
PLANNING DATA	from PLAN
• Cash outlays for plant construction for each year of simulation	
• Details of plants coming on line	
(All information broken down by asset categories)	

D.2 FINANCIAL Module Assumptions

This conceptual model, like other similar regulatory models, incorporates a number of assumptions and approximations. It entails a uniformity of approach to regulation which does not, of course, exist among the many public bodies involved. The institutional complexities surrounding the regulatory process set limits on the analysis that can be made using the regulatory model.

The conceptual model of regulatory control assumes fundamentally that regulation acts to set prices so that the revenue collected will equal the actual costs of providing service. These costs are to be understood to include an appropriate return to investor/owners of the utilities. Prices so set are adjusted among different groups of customers in accordance with several criteria: fairness to both consumers and investors; efficiency of resource management; adequacy and reliability of future supply; and similar desirable attributes of an ideal pricing and regulatory system. Below we discuss several of the principal assumptions incorporated into the operation of the FINANCIAL module.

Constancy of Current Parameter Values and Accounting and Tax Practices. The FINANCIAL module is required to make implicit assumptions regarding the external financial environment of the electric utility industry over the simulation period. A key assumption in this regard is that conditions will either remain as they are today or closely follow the historical pattern that has developed over the past 20 years. The model uses a predetermined inflation rate and external financing mix throughout the simulation period. It is implicitly assumed that accounting practices and regulations for income-tax determination will remain the same as they are now. The model incorporates current changes in tax laws and accounting procedures.

Constancy of the Cost of Capital at All Financing Levels. Just as the financing mix ratios are predetermined, the cost of capital is set at an exogenously determined level for each type of security. This cost then remains constant throughout the model and all new issues of debt and equity pay the specified return. It should be noted that in the case of common stock, because of well-known forecasting difficulties, no attempt is made to predict the market price of the stock or earnings per share. Thus, dividends are based on a specified percentage return for each dollar of common stock outstanding and are not determined on a per-share basis.

Responsiveness of the Rate-Setting Environment. The FINANCIAL module assumes a responsive rate-setting environment. Revenues in any given year are a result of an average electricity price determined in the previous year. This average price is based upon what revenue requirements would have been in effect in that year in order for the utility to recover all its costs and an allowed return to common stockholders. Because annual electricity demand growth rates are exogenously specified, there is an implicit assumption that price sensitivity and customers' substitution of energy forms due to relative energy prices are not significant factors. Although it is possible that a return greater or less than the allowed return will actually occur during the simulation as a result of fluctuations in the real cost of electricity and variations in financing levels, the realized rate of return over the simulation period will not vary dramatically from the allowed return specified.

Neutral Effect of Nonelectricity Operations. A number of items on an electric utility's balance sheet and income statement are outside the scope of electricity operations but nonetheless must be accounted for. These items include net income from nonelectricity operations, nonoperating income, non-income taxes, and other assets and other credits. The initial amounts of these items are determined from FPC forms for 1975. During each year of the simulation they are assumed to increase at the inflation rate.

Input Financial and Economic Parameters. The input parameters and assumptions, including real cost escalation rates, can significantly influence the cost projections. Table D-2 lists the basic financial parameters and cost escalation rates used in this study. The principal economic results of the scenario projections are given in Section 3.

Table D-2

Baseline Economic and Financial Parameters

Parameter	Value	Period
Amortization rate of investment tax credits	.0333	1976-2000
Common stock proportion — total capitalization	.35	1976-2000
Construction work in progress interest rate	.064	1976-2000
Operating cost coefficient in rate base formula	.125	—
Depreciation rate: book use		
Steam	.028571	35 yrs
Nuclear	.033333	30 yrs
Hydro	.015385	65 yrs
Other electric plant	.033333	30 yrs
Transmission	.028571	35 yrs
Distribution	.04	25 yrs
Pollution control	.2	5 yrs
Depreciation rate: tax use		
Steam	.035714	28 yrs
Nuclear	.05	20 yrs
Hydro	.02	50 yrs
Other electric plant	.05	20 yrs
Transmission	.0333	30 yrs
Distribution	.0333	30 yrs
Pollution control	.2	5 yrs
Federal income tax rate	.46	1976-2000
Investment tax credit rate	.1	1976-2000
Coefficient of tax allowable in rate base formula	.06	1976-2000
Percent of investment tax credit normalization	100	1976-2000
Percent of accelerated depreciation	100	1976-2000
Reciprocal of the average term of issue — long-term debt	.04	

Table D-2 (Continued)

Parameter	Value	Period
Inflation rate	.07	1976-2000
Long-term debt rate	.09	1976-2000
Rate-of-return common equity	.13	1976-2000
Rate-of-return preferred equity	.10	1976-2000

Schedule of state income tax rates

Maine	.07	North Carolina	.06
New Hampshire	.08	South Carolina	.06
Vermont	.075	Georgia	.06
Massachusetts	.0833	Florida	.05
Rhode Island	.08	Kentucky	.058
Connecticut	.10	Tennessee	.06
New York	.10	Alabama	.05
New Jersey	.075	Mississippi	.04
Pennsylvania	.095	Arkansas	.06
Ohio	.00	Louisiana	.08
Indiana	.06	Oklahoma	.04
Illinois	.04	Texas	.0
Michigan	.0235	Montana	.0675
Wisconsin	.079	Idaho	.065
Minnesota	.12	Wyoming	.00
Iowa	.1	Colorado	.05
Missouri	.05	New Mexico	.05
North Dakota	.06	Arizona	.105
South Dakota	.00	Utah	.04
Nebraska	.044	Nevada	.00
Kansas	.0675	Washington	.00
Delaware	.087	Oregon	.075
Maryland & DC	.07	California	.09
Virginia	.06	Alaska	.00
West Virginia	.06	Hawaii	.00

Table D-2 (Continued)

Parameter	Value	Period
Construction costs (1975 $/kWe)		
Nuclear	711	
High heat value coal	484	
Low heat value coal	504	
Oil (steam)	377	
Gas (steam)	377	
Conventional hydro	569	
Pumped storage	192	
Combustion turbine and internal combustion	141	
Combined cycle	257	
Geothermal	570	
Fuel cell	343	
Exotic devices	1,000	
Cost trends (yearly % increases in 1975$)		
Nuclear construction	2.50	1976-2000
Coal construction	2.00	1976-2000
Other construction	2.00	1976-2000
Operation costs	1.50	1976-2000
Maintenance costs	2.00	1976-2000
Transmission costs	2.00	1976-2000
Pollution control costs	1.50	1976-2000

Fuel price trends (yearly % increases in 1975$)

Oil	Gas	Nuclear	
-7.18	29.92	16.00	1976
6.67	18.73	20.70	1977
17.89	17.89	16.40	1978
17.39	17.89	9.20	1979
19.05	17.89	7.87	1980
3.53	17.89	3.53	1981
3.53	17.89	3.53	1982
3.53	17.89	3.53	1983
3.53	17.89	3.53	1984
3.53	17.89	3.53	1985
3.53	3.53	3.53	1986-2000

Coal price trends (See Appendix B, Table B-14)

Table D-2 (Continued)

Parameter	Value		Period
Base-year fuel prices (1975)			
Oil Prices Vary by State and Sulfur Content			
Residual (avg.)	2.02	(1975\$/10^6 Btu)	
Distillate	2.24	(1975\$/10^6 Btu)	
Natural gas	0.75	(1975\$/10^6 Btu)	
Nuclear fuel	16.51	(1975\$/kW-yr)	

APPENDIX E

PARTICULATE AND SULFUR DIOXIDE CONTROL

E.1 Particulate Control

E.2 Sulfur Dioxide Control

E.3 References

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APPENDIX E

PARTICULATE AND SULFUR DIOXIDE CONTROL

E.1 Particulate Control

The USM uses either cold-side electrostatic precipitators (ESPs), hot-side ESPs, or fabric filters for control of particulate matter from utility boilers. The model chooses the least-cost control strategy, comparing hot-side ESPs with fabric filters for lignite and subbituminous coals having less than 1.5 percent sulfur, and cold-side ESPs with fabric filters for other coals. In most cases, the USM uses fabric filters for the low-sulfur lignite and subbituminous coals and cold-side ESPs for other coals. In fact, cold-side ESPs were built by the USM for all units in the ORBES counties, since low-sulfur western coals were excluded.

Electrostatic Precipitators

The coal heating value, coal ash content, and applicable particulate emission limit are used to calculate the ESP collection efficiency required for particulate control. The collection efficiency, in turn, is used with the boiler gas flowrate and coal sulfur content to determine the required ESP size. The relationship shown graphically in Figure E-1 is used to determine ESP size as a function of coal sulfur content. The calculated ESP size is increased by 50 percent, representing a conservative design, to agree with values used in the PEDCo study[1] for EPA. Where low-sulfur western coals are burned, the ESP size is increased by an additional 30 percent, again in accordance with PEDCo estimates.

Once the ESP size is determined, capital and operating costs are calculated using a cost model based again on engineering estimates provided by PEDCo. If the ESP installation is a retrofitted one, capital costs are increased by 50 percent to cover the cost of removing any existing control equipment and the cost of

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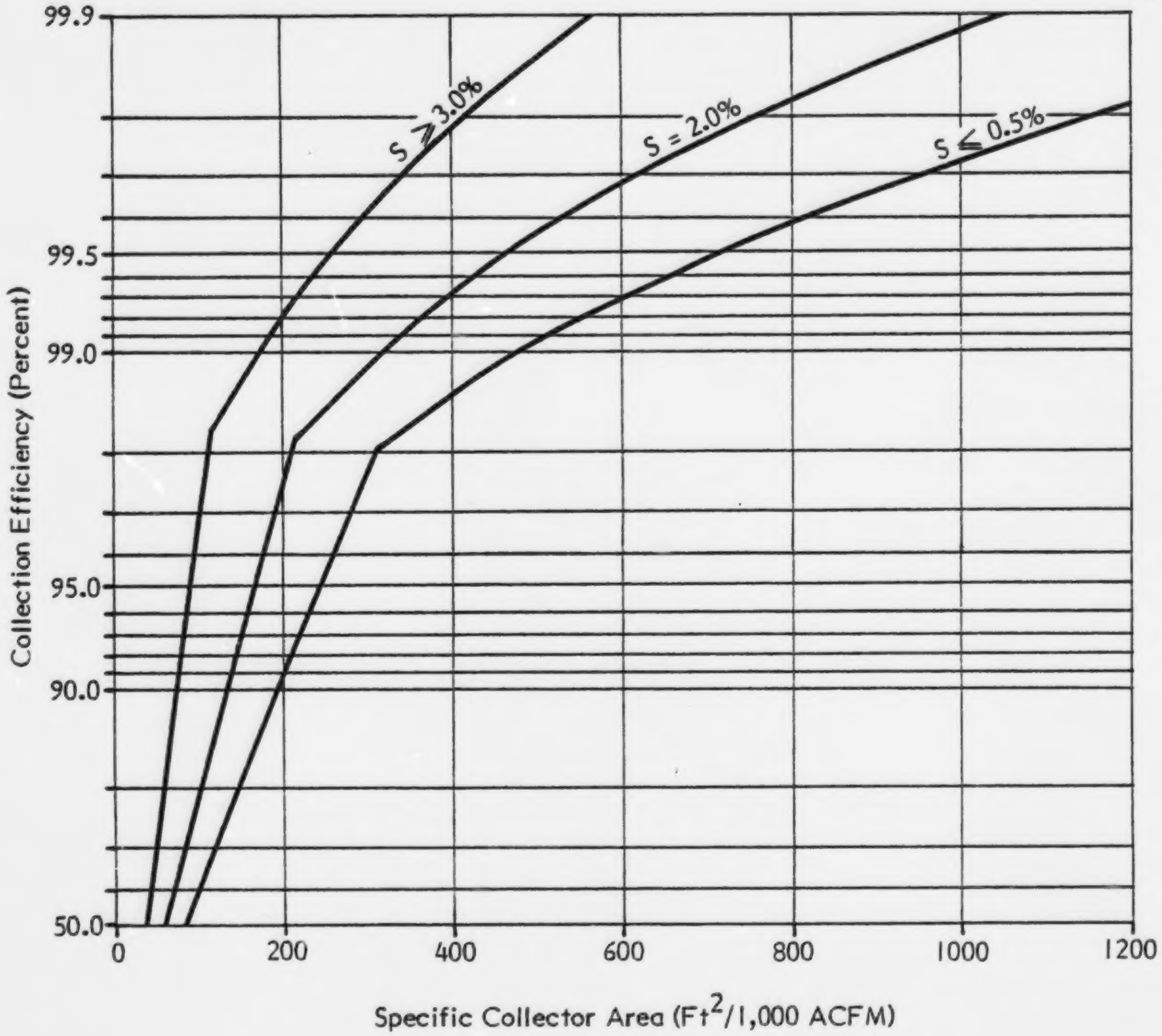
Figure E-1

Relationship Between ESP Collection Efficiency and Specific Collector Area for Various Coal Sulfur Contents



increased ducting that may be required. The electricity used to energize the ESP and to power the induced draft fans is assumed to be provided by the generating unit being controlled and is treated accordingly as a capacity penalty. In other applications of the particulate control cost model (such as in making coal assignments), the cost of electricity is included in the operating cost.

Fabric Filters

The fabric filter performance model is relatively simple in that the air-to-cloth-ratio (cubic feet per minute of gas flowrate per square feet of fabric) is assumed to be 20 in all cases.

Once the fabric area is determined, costs are calculated using a model based on PEDCo engineering estimates.[1] Retrofitted fabric filter installations are assumed to cost 67 percent more than new-unit installations. As with the ESP, electricity used for the induced draft fans is treated as a capacity penalty in the USM and as an operating cost in making coal assignments.

E.2 Sulfur Dioxide Control

The USM SO_2 control performance and cost models are based on PEDCo[1] engineering and cost estimates for lime, limestone, and magnesium oxide FGD systems. The models can be used to predict the costs of new-unit or retrofitted FGDs for generating plants of between 25 MW and 2,000 MW in size burning coal of any sulfur content and meeting any emission limit, for any averaging time.

The three FGD systems are modular in design, with module sizes of between 50 MW and 130 MW except for plants of less than 50 MW in size. One redundant module is included for all systems of 100 MW or greater for a design reliability of 90 percent. The design of the three FGD systems is based on a three-stage turbulent contact absorber (TCA).

Within the model, plant characteristics, coal properties, and emission limits are used to determine the required rate of sulfur dioxide removal in pounds per hour and the required gas flow rate in actual cubic feet per minute for an FGD system having an annual average removal efficiency of 90 percent or greater. If a given generating plant needs to remove less than 90 percent of the SO_2 produced to meet applicable emission limits, an FGD system with an efficiency of 90 percent will be used to scrub a portion of the flue gas. The remaining flue gas will be bypassed and mixed with the scrubbed gas to yield the required SO_2 emissions and to reduce or eliminate the fuel required for reheating the flue gas. If 90 percent or more of the SO_2 must be removed, an FGD system having the required efficiency up to the limits of technology will be used to scrub the entire flue gas stream.

The cost of such equipment as pumps, hold tanks, feed preparation equipment, and sludge ponds is based on the sulfur dioxide removal rate, while the cost of such items as fans, absorbers, and soot blowers is based on the gas flow rate. Likewise, operating costs are based on either the sulfur dioxide removal rate (e.g., raw material) or the gas flow rate (e.g., electricity, reheat steam or oil).

Outputs from the FGD model include:

- Capital cost
- Fixed operating cost (independent of plant capacity factor)
- Variable operating cost (dependent on capacity factor)
- Removal efficiency
- Scrubber size
- Capacity penalty (plant capacity used to operate the FGD system)
- Heat rate penalty (accounts for fuel required to operate the FGD system)
- Water used and water cost

- Oil used for magnesium oxide regeneration
- Oil used for reheat
- Annual sludge generation

SO_2 emissions are calculated on the basis of the uncontrolled emission rate and the required removal efficiency.

Input data required for the FGD model include:

- Individual generating-unit characteristics
  - Size
  - Age (new or retrofit)
  - Heat rate
- Coal properties
  - Heating value
  - Composition (C, H, O, N, S, H_2O, ash)
  - Class (bituminous, subbituminous, lignite)
- Environmental factors
  - Emission limit (specific limits: percentage removal, ceiling, floor, and averaging time)
- Economic factors
  - Year scrubber was built (escalation, inflation)

With respect to FGD costs for new versus retrofitted plants that are otherwise identical, burn the same coal, and meet the same emission standard, the USM calculates the capital cost for a retrofitted scrubber to be between about 5 and 10 percent higher than for a limestone scrubber installed in a new plant. However, since existing units on which scrubbers are retrofitted are generally smaller than new units, the capital cost per kilowatt is usually much lower for the new units because of the economies of scale.

This point is illustrated below for two units burning Northern Appalachian bituminous coal and meeting a 1.2 lb/MBtu (annual average) emission limit. The capital cost per kilowatt for the retrofitted scrubber is 90 percent greater than for the new scrubber. The unit on which the FGD system is retrofitted is 200 MW in size, which is typical of existing SIP regulated units, while the NSPS unit is 650 MW in size. For the new unit, the FGD system is built at the same time as the rest of the plant.

Unit Designation	SIP	NSPS
Size (MW)	200	650
FGD system	Retrofitted limestone	New limestone
Coal	Northern Appalachian	Northern Appalachian
Emission limit (lb/MBtu)	1.2	1.2
Percent SO_2 removal	72	72
Capital cost (1975)	\$23.9 million	\$40.7 million
Cost per kW (1975)	\$119.5	\$62.6

E.3 References in Appendix E

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APPENDIX F

TABLES OF RESULTS BY SCENARIO

- Generating Capacity in ORBES Counties
- Generation in ORBES Counties
- Regional Average Electricity Prices
- SO_2 Emissions in ORBES Counties
- Particulate Emissions in ORBES Counties
- NO_x Emissions in ORBES Counties

Table F-1

Scenario 1

Capacity (Gigawatts) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	2.1	72.7	2.4	3.9	81.1
1985	9.6	90.1	3.4	3.6	106.7
1990	10.5	102.9	2.9	5.7	122.0
1995	11.3	124.6	2.2	6.6	144.7
2000	11.1	136.3	2.0	7.1	156.5

Generation (Terawatt-Hours) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	10.0	363.1	2.3	4.5	379.9
1985	54.4	476.8	4.2	4.9	540.3
1990	60.0	526.0	3.1	5.1	594.2
1995	64.1	629.7	2.6	5.3	701.7
2000	62.9	669.4	2.4	5.2	739.9

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Table F-2

Scenario 2

Capacity (Gigawatts) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	2.1	72.7	2.4	3.9	81.1
1985	9.6	90.6	3.4	4.6	108.2
1990	10.5	103.8	2.9	5.8	123.0
1995	11.3	125.4	2.2	6.7	145.6
2000	11.1	137.0	2.0	7.1	157.2

Generation (Terawatt-Hours) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	10	363.1	2.3	4.5	379.9
1985	54.4	477.0	4.3	4.9	540.6
1990	60.0	532.6	3.2	5.1	600.9
1995	64.1	632.9	2.5	5.1	704.6
2000	62.9	670.5	2.3	5.1	740.8

Table F-3

Scenario 2d

Capacity (Gigawatts) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	2.1	72.7	2.4	3.9	81.1
1985	9.6	91.9	3.4	4.6	109.5
1990	10.5	105.0	2.9	5.8	124.3
1995	11.3	126.5	2.2	6.6	146.6
2000	11.1	138.0	2.0	6.1	158.2

Generation (Terawatt-Hours) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	10.0	363.1	2.3	4.5	379.9
1985	54.4	463.3	3.3	4.8	525.8
1990	60.0	505.6	2.6	5.2	573.4
1995	64.1	609.3	2.1	5.2	680.7
2000	62.9	668.2	1.8	5.1	738.0

Table F-4

Scenario 4

Capacity (Gigawatts) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	2.1	72.7	2.4	3.7	81.1
1985	7.4	83.9	3.4	4.4	99.0
1990	10.3	79.1	2.9	5.0	97.3
1995	11.3	91.0	2.2	5.4	109.0
2000	11.1	101.8	2.0	5.9	120.8

Generation (Terawatt-Hours) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	10.0	363.1	2.3	4.5	379.9
1985	42.3	391.3	1.6	4.5	439.7
1990	58.4	386.3	2.5	5.0	452.2
1995	64.1	442.0	1.9	5.1	513.1
2000	62.9	486.5	1.6	5.0	556.0

Table F-5

Scenario 7

Capacity (Gigawatts) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	2.1	72.7	2.4	3.9	81.1
1985	9.5	90.0	3.4	4.6	107.5
1990	10.5	119.6	2.9	6.7	139.6
1995	11.3	156.1	2.2	8.3	177.7
2000	11.1	186.9	2.0	9.9	209.8

Generation (Terawatt-Hours) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	10.0	363.1	2.3	4.5	379.9
1985	54.4	464.1	4.3	4.7	527.5
1990	59.9	576.8	3.3	5.1	645.1
1995	64.1	739.5	2.7	5.2	811.5
2000	62.9	865.1	2.5	5.3	935.8

Table F-6

Scenario 7a

Capacity (Gigawatts) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	2.1	72.7	2.4	3.9	81.1
1985	9.5	90.0	3.4	4.6	107.5
1990	10.5	119.6	2.9	7.8	139.6
1995	11.3	156.1	2.2	8.3	177.7
2000	11.1	186.9	2.0	9.9	209.8

Generation (Terawatt-Hours) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	10.0	363.1	2.3	4.5	379.9
1985	54.4	452.2	4.4	4.8	515.8
1990	59.9	560.5	3.4	5.1	628.9
1995	64.1	715.2	2.9	6.0	788.2
2000	62.9	830.7	2.6	5.3	901.5

Table F-7

Scenario 7b

Capacity (Gigawatts) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	2.1	72.7	2.4	3.9	81.1
1985	9.5	90.0	3.4	4.6	107.5
1990	10.5	118.2	2.9	6.7	138.3
1995	11.3	153.7	2.2	8.2	175.4
2000	11.1	184.7	2.0	9.6	207.4

Generation (Terawatt-Hours) by Plant Type

Year	Nuclear	Coal	Oil	Hydro + Other	Total
1976	10.0	363.1	2.3	4.5	379.9
1985	54.3	464.2	4.3	4.7	527.5
1990	59.9	572.5	3.2	5.2	640.8
1995	64.1	721.7	2.6	5.2	793.6
2000	62.9	836.9	2.5	5.3	907.6

Table F-8

Price of Electricity (1975¢/kWh) to Ultimate Consumers under Alternative Scenarios

	Scenario						
Year	1	2	2d	4	7	7a	7b
1976	2.58	2.58	2.58	2.58	2.58	2.58	2.58
1985	4.21	3.87	3.10	3.62	3.80	3.86	3.80
1990	4.07	3.93	3.52	3.50	4.11	4.19	4.27
1995	4.30	4.18	3.87	3.93	4.53	4.60	4.82
2000	4.71	4.64	4.44	4.63	5.53	5.60	5.70

Table F-9

SO_2 Emissions (10^6 Tons) under Alternative Scenarios

Year	Scenario						
	1	2	2d	4	7	7a	7b
1976	8.94	8.94	8.94	8.94	8.94	8.94	8.94
1985	2.99	6.10	10.10	5.66	5.93	4.69	5.94
1990	2.74	5.55	9.45	5.13	6.07	3.94	5.61
1995	2.73	5.16	8.66	4.54	6.24	3.68	5.34
2000	2.55	4.35	7.55	3.93	6.06	3.34	4.71

Table F-10

Electric Utility Particulate Emissions (10^6 Tons) under Alternative Scenarios

Year	Scenario						
	1	2	2d	4	7	7a	7b
1976	1.38	1.38	1.38	1.38	1.38	1.38	1.38
1985	0.25	0.25	1.53	0.22	0.25	0.24	0.25
1990	0.24	0.22	1.37	0.20	0.25	0.23	0.23
1995	0.23	0.21	1.23	0.18	0.26	0.23	0.23
2000	0.21	0.19	1.06	0.16	0.26	0.21	0.21

Table F-11

Electric Utility NO_x Emissions (10^6 Tons) under Alternative Scenarios

Year	Scenario						
	1	2	2d	4	7	7a	7b
1976	1.49	1.49	1.49	1.49	1.48	1.48	1.48
1985	1.69	1.71	1.82	1.44	1.67	1.58	1.67
1990	1.74	1.77	1.88	1.38	1.93	1.79	1.86
1995	1.96	1.98	2.08	1.46	2.34	2.16	2.21
2000	1.99	2.00	2.16	1.51	2.63	2.41	2.46

APPENDIX G

CHANGES IN SIP EMISSION STANDARDS AND THE IMPORTANCE OF EMISSION AVERAGING TIMES

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APPENDIX G

CHANGES IN SIP EMISSION STANDARDS AND THE IMPORTANCE OF EMISSION AVERAGING TIMES

The SIP SO_2 emission standards that will be applicable in 1985 were subject to uncertainty at the time of this study and continue to be so today. In order to maintain consistency throughout this and other ORBES support research, the SIP standards assumed were those known in early 1979. Since that time a number of the SIPs for power plants have been changed — in some cases to permit higher SO_2 emission rates.

SIP specifications for SO_2 include an emission limit and also an averaging period for measurements of SO_2 emissions. If an averaging time is not specified, "long term" averaging is implied. (Compliance is determined by taking the emission values averaged over the specified averaging period and comparing them with the emission limit.) It should be noted that the averaging period can significantly influence the average emission rate and hence the annual emissions. This is due to the variability of the sulfur content of coal: the long-term average emission rate must be sufficiently below the SIP emission limit to ensure that fluctuations in averaged values of coal sulfur content do not cause violations of the SIP limit.* Hence, the shorter the averaging period, the lower the coal's long term average sulfur content must be for the coal to comply with a specified emission limit.

To illustrate the impact of averaging times we have looked at two cases, using a June 1980 list of SO_2 SIP emission limits for each generating unit in the ORBES area to arrive at additional estimations of SO_2 emissions. In one case we have interpreted each SIP limit as based on an annual ("long term") averaging period. In the other case, we have interpreted each limit as enforced over the state SIP

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* Within a certain confidence level and allowing for a specified rate of exceedances.

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averaging periods: 2 hours in Kentucky; 24 hours in Ohio, West Virginia, and Indiana; 2 months in Illinois; and annual in Pennsylvania. Under certain assumptions regarding plant size and coal sulfur variability, we find that SIP-unit emissions will equal the emission limit when the averaging period is annual, and that they will be lower than the limit by roughly a factor of 1.6 when a 3-hour limit is not to be exceeded; by a factor of 1.5 under a 24-hour period, and lower by a factor of 1.3 under a monthly averaging period. These factors depend significantly on the assumed variations in coal sulfur content (which depend in turn upon other considerations, including the quantity of coal consumed).

These results under assumptions similar to Scenario 2 for coal-fired and nuclear generation indicate that adherance to the stated averaging times for the latest (June 1980) SIP standards for 1985 will lead to ORBES county SO_2 emission levels in 2000 that are nearly the same as those of Scenario 2 (4.4 million tons). Conversely, the use of annual averaging periods for these same absolute limits on each unit will result in ORBES county SO_2 emission levels of about 5.1 million tons. Enforcement of the annual rather than the stated averaging times, then, could increase ORBES county SO_2 emissions in the year 2000 by 0.7 million tons. Hence, the specified averaging period is an important element of the SIP standards and will exert considerable influence over future annual emissions levels in the ORBES counties.